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ANALYSIS OF THE TRADE-OFF OF EXPLORATION BETWEEN ONSHORE AND OFFSHORE REGIONS AND POTENTIAL ENVIRONMENTAL HAZARDS AND SAFEGUARDS

VOLUME I: REPORT

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The attractiveness of onshore and offshore regions based solely upon the location of oil and natural gas resources and the costs of exploration is assessed. The impact of government policies on exploration, e.g. costs of lease acquisition, taxes, environmental regulations and other policies, is analyzed. Environmental hazards which can be anticipated from future exploration patterns are identified, and current and potential government policies to safeguard the environment are evaluated.

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I

SUMMARY

Purpose

The purpose of this study is twofold:

- to assess the attractiveness of onshore and offshore regions for future oil and natural gas exploration in the absence of government policy and to identify the environmental hazards which are suggested by future exploration patterns; and

- to determine whether current government policies impact on the exploration decision in a manner which supports or weakens environmental considerations and to identify policy options which can strengthen the government's role in reducing the environmental hazards of future exploration.

As a first step in meeting the study objective, we compared the attractiveness of onshore and offshore regions based solely upon the location of oil and natural gas resources and the costs of exploration. Subsequently, the impact of government policies on exploration, e.g. costs of lease acquisition, taxes, environmental regulations and other policies, was analyzed. To identify the environmental hazards which can be anticipated from future exploration patterns, we determined which onshore and offshore regions are being traded on the margin, identified potential environmental hazards of exploration of these regions, and evaluated current and potential government policies to safeguard the environment.

Approach

Our assessment of the relative attractiveness of onshore and offshore regions for future oil and gas exploration is based on two analyses:*

- a comparison of recent estimates of remaining discoverable reserves of oil and natural gas to determine the magnitude of remaining discoverable reserves in onshore and offshore regions.

- a ranking of the regions according to their attractiveness for future exploration on the basis of twenty-five indicators:

    -- 12 measure the amount of resources and their depletion to date in each region;

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* See page 22 for a list of the ten regions used in this study.

-- 13 measure the success and cost of past exploratory and developmental drilling in each region. The regions were ranked from most to least favorable for each indicator. Our final assessment is based on the frequency that major producing regions are ranked very favorably (among the highest three) and an assessment of which indicators are most important.

Virtually no exploratory drilling has occurred in the Atlantic Coast or along the Alabama, Mississippi and Florida coastlines, so data for regional comparisons are limited to estimates of discoverable resources for these regions. Except for offshore California, this also is true of the Pacific Coast. Offshore Louisiana and Texas has been a major producing region for over 10 years, so adequate data for comparative analyses are available for this region.

To assess the impact of government policies, economic conditions, and cost factors on the offshore exploration decision, a mathematical model which simulates the operation of a typical offshore oil and natural gas producing tract is used. Tracts in the Outer Continental Shelf (OCS) are leased by competitive bidding by the Department of Interior. A fixed royalty rate, currently .167, and competitive cash bonus are required. In the past, petroleum companies have paid very large bonuses to lease OCS acreage, presumably with the expectation of finding substantial reserves and of costs and prices which would permit profitable operations. These bonus payments consume a portion of the difference between the present value of the expected revenues and the costs of discovering and producing the reserves. The large bonus payments paid in the past suggest that operators evaluate the real resource costs of OCS oil and gas to be relatively low per unit of output compared to expected revenues. The assumptions about whether profitable operations can be anticipated are based on perceptions of future price levels, operating costs, and various government policies.

The mathematical model computes the Expected Present Value (EPV) of revenues less all costs except the lease bonus payment. The model includes most parameters to which the offshore exploration decision is sensitive -- taxes, the royalty rate, prices, and costs of exploration and production. If the Expected Present Value is positive, a firm will be willing to pay a bonus equal to or less than the Expected Present Value to acquire the lease. Thus, the model shows the maximum bonus a firm would be willing to pay.

Our objective is to test the sensitivity of the offshore exploration decision to various changes in government policies, economic conditions, and costs. To accomplish this task, we first establish the conditions of a base case, against which we test the sensitivity of changes in key variables. We use as our base case a typical operation on a 5,000 acre tract in the Gulf of Mexico.

We then develop a hypothesis which we test by a series of sensitivity analyses. We hypothesize that, under a reasonable range of Federal policy alternatives (short of a restriction or cessation of offshore leasing), prices, and operating conditions, the Expected Present Value of the typical offshore tract will remain positive. That is, government policies have no impact on the decision to explore domestic offshore versus onshore regions. Instead, they affect only the size of the bonus paid to obtain offshore drilling rights.

Finally, to assess the environmental hazards of future exploration patterns, we first determine which onshore and offshore areas are being traded on the margin by reviewing historical data on the number of wells, drilling footage, and drilling expenditures by region to identify regions which are increasing their share of exploratory activity. The impact of Federal public land and Outer Continental Shelf leasing policies, state conservation regulations, economic conditions, tax policy, import policy and other direct and indirect supply controls on the tradeoff of exploration among regions also is reviewed. Our assessment of environmental hazards focuses on offshore exploration and production, because past exploratory drilling trends and Federal policies suggest that offshore regions will continue to increase their share of exploration and production relative to lower 48 onshore regions. Mitigating Federal regulations are discussed and areas in which EPA currently or potentially has a major responsibility to minimize environmental damage due to oil and gas exploration and production are identified.

Results

Relative Attractiveness of Onshore and Offshore Regions for Future Exploration

Discoverable Reserve Estimates: The two most recent estimates of remaining discoverable oil differ by less than 10 percent. The National Petroleum Council (NPC) estimates that discoverable oil reserves were 385 billion barrels in 1972 and the USGS estimates that they were 422 billion barrels. Since these estimates of necessity are speculative -- based on a variety of geological methods and extrapolations -- this difference is relatively minor. Based on 1972 production levels, the NPC estimate suggests that current production can be sustained for 118 years and the USGS suggests it can be sustained for 128 years. Much greater divergence exists in the latest estimates of discoverable natural gas. The Potential Gas Committee (PGC) estimates that discoverable reserves total 1146 trillion cubic feet, while the USGS places the figure at 2100 trillion cubic feet. The NPC and PGC estimates are based on the most comprehensive geological studies conducted to date. The USGS estimate for oil is based on extrapolation of historical drilling results to all unexplored rocks on an equal basis and the estimate for gas is derived by applying a gas-oil ratio to estimated oil-in-place. The NPC and PGC estimates generally are the most widely accepted and are used for regional analyses in this report.

While substantial differences exist in the reserve estimates we have reviewed and estimates are not directly comparable because they are based on different analyses, we nevertheless conclude that consensus exists on two points:

- A substantial proportion of remaining recoverable reserves of both oil and natural gas lie in lower 48 offshore regions; and
- The Gulf of Mexico remains the most attractive lower 48 offshore region.

The following table illustrates these points:

TABLE 1

SUMMARY OF THE DISTRIBUTION OF DISCOVERABLE OIL AND NATURAL GAS RESERVES

	Percent Found In:	
Source of Estimate	Lower 48 Offshore (As a Percent of Total U.S.)	Gulf of Mexico (As a Percent of Lower 48 Offshore)
Oil:		
NPC	24%	31%
USGS	27	55-60**
BLM	--*	57
Natural Gas:		
PGC	20	65
USGS	30	76**
BLM	--*	51

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* BLM estimates show Outer Continental Shelf reserves for offshore regions only so they were used only to develop a distribution among offshore regions.

** Based on 1974 updated figures.

The Gulf is estimated to have 31 to 60 percent of lower 48 offshore discoverable oil reserves and 51 to 76 percent of lower 48 offshore discoverable gas reserves. (Except for the Potential Gas Committee (PGC) estimate, the Gulf of Mexico estimates shown include offshore Alabama, offshore Mississippi and the Florida Gulf Coast. Separate reserve estimates are not available for these states.)

Regional Analyses: Natural Gas: Our analysis of the regional distribution of natural gas and the costs of exploratory drilling indicates that the Gulf of Mexico is more attractive than any major producing lower 48 onshore region for future exploration and production of natural gas. Table 2 shows how the Gulf compares to the Southwest, South Louisiana and South Texas, and Alaska for eight indicators.

The Gulf does not rank highly for proved reserves, but because proved reserves is the most conservative reserve estimate -- measuring only natural gas in discovered reservoirs which is expected to be recoverable under current operating and economic conditions -- it is not an important indicator of where future exploration can be expected. The most important indicator available is the PGC estimate of probable potential supply. This is natural gas in existing fields which has not been proved. It includes future extensions of existing pools and future new pool discoveries in known productive reservoirs. The Gulf of Mexico and South Louisiana and South Texas both rank highest on this measure and are estimated to each contain 57 tcf of probable potential supply.

Exploratory drilling can be classified by three drilling objectives:

1. Extension of known pools.
2. Discovery of new pools in existing fields (new pool wildcats).
3. Discovery of new fields (new field wildcats).

Drilling new field wildcats in areas never before productive is the most speculative type of exploratory drilling.

Tapping estimated probable potential supply instead requires drilling in existing fields to extend known pools or discover new pools. Future exploration in existing fields where familiarity with geological conditions has been developed, and transportation and producing facilities are accessable, is more likely than extensive exploration in new fields to meet midterm demand. Proved reserves in the Gulf of Mexico are adequate to meet current production levels for 21 years and probable potential supply could sustain current levels for another 31 years. The Southwest and South Louisiana and South Texas each have proved reserves that will sustain current production levels only for about 9 years and probable potential supply will only sustain current levels for another 5 to 6 years. Only 30 percent of discoverable natural gas has been proved to date in the Gulf. In contrast, more than half the total discoverable reserves in the Southwest and South Louisiana and South Texas already are proved.

The Gulf also ranks highly in potential supply at shallow depths. Since drilling costs per foot increase substantially with well depth, this is a good indicator for the likelihood of all types of exploratory drilling.

TABLE 2

INDICATORS OF THE LIKELIHOOD OF FUTURE EXPLORATION FOR NATURAL GAS

Indicators	Gulf of Mexico	Southwest	South Louisiana and South Texas	Alaska
1. Proved Reserves (trillion cubic feet)	39 tcf	75 tcf	89 tcf*	32 tcf
2. Probable Potential Supply (trillion cubic feet)	57 tcf*	46 tcf	57 tcf*	54 tcf
3. Potential Supply less than 200 meters deep offshore and 15,000 feet deep onshore (tcf)	133 tcf	161 tcf*	79 tcf	148 tcf
4. Ultimate Recovery as Percent of Ultimate Discovery	30%	53%	66%	8%
5. Avg. Depth of Gas Wells	10,904 ft.	5,496 ft.	8,704 ft.	7,286 ft.
6. Avg. Cost/Foot of Gas Wells	$69.56	$27.38	$28.90	$132.47
7. Proved Reserves Added/Foot of Gas Wells (million cubic feet)	11.5 mcf*	4.1 mcf	2.4 mcf	10.8 mcf
8. Avg. Drilling Cost/ Million Cubic Feet of New Proved Reserves	$.063	$.055	$.075	$.005*

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*Most favorable ranking among all regions.

As expected, exploration in offshore regions is much more expensive than onshore regions. The average cost per foot of gas wells drilled was more than twice as high in the Gulf than any onshore region and the average well depth also was substantially greater. However, the productivity of the Gulf's natural gas wells -- measured as proved reserves added per foot of drilling -- was about three times greater than in the Southwest and five times greater than in South Louisiana and South Texas. Eleven and one half mcf of proved reserves were added per foot of drilling in the Gulf. The Gulf's high productivity largely compensates for higher drilling costs so that the drilling cost per million cubic feet of new proved reserves is 15 percent greater than in the Southwest but 19 percent less than in South Louisiana and South Texas.

Regional Analysis: Oil: While results of our analysis of the distribution of oil reserves and exploration are less clear, we nevertheless conclude that the data suggest that the Gulf of Mexico and the West are the two most attractive regions for future oil exploration. Table 3 shows how the Gulf compares to the West, Southwest and Alaska for seven indicators.

Proved reserves are lowest in the Gulf and are adequate to sustain current production levels for only about six years, compared to five years in the West and 10 in the Southwest. This suggests that exploration in the Gulf and the West must proceed more rapidly than in the Southwest to sustain production, if discoverable reserves are available. NPC estimates of discoverable reserves are high for both regions. Remaining discoverable oil is adequate to meet current production levels for 68 years in the Gulf and 105 years in the West, compared to only 35 years in the Southwest.

The Gulf appears more attractive than the West for several indicators. Ultimate recovery as a percent of original oil-in-place is much higher. This measures the amount of oil in known reservoirs expected to be producable under current operating and economic conditions. (Portions of the remaining oil may become profitably recoverable with price increases and improved technology.) Additionally, oil wells in the Gulf generate more barrels of new proved oil reserves. Sixty-four barrels per foot were added in the Gulf compared to 49 barrels in the West and 24 barrels in the Southwest. The 30 percent difference in drilling costs between the Gulf and the West is relatively small, contrasted with the range in all lower 48 onshore regions of $.23 to $.61. Offshore drilling costs generally are substantially higher than onshore costs. However, the cost of onshore drilling can be expected to increase because much of the "easy-to-find oil" at shallow depths has been discovered. Remaining discoverable onshore reserves frequently are located in stratigraphic traps and complex structures. In contrast, a substantial portion of offshore reserves are located in simple structural entrapments. These factors may cause cost differentials between onshore and offshore drilling to narrow. Additionally, drilling costs comprise only a fraction of total costs, so small drilling cost differences can easily be offset by other costs. Thus, relatively minor higher current drilling costs probably do not significantly reduce a region's attractiveness for future exploration if recoverable reserves are estimated to be high.

TABLE 3

INDICATORS OF THE LIKELIHOOD OF FUTURE EXPLORATION FOR OIL

Indicators	Gulf of Mexico	Southwest	West	Alaska
1. Proved Reserves (billions of barrels)	3 bb	12 bb	5 bb	10 bb
2. Remaining Discoverable Oil-in-Place (billions of barrels)	27 bb	45 bb	88 bb	119 bb
3. Ultimate Recovery as Percent of Original Oil-in-Place	47 %	30 %	26 %	39 %
4. Av. Depth of Oil Wells	10,591 ft.	4,237 ft.	4,587 ft.	11,042 ft.
5. Av. Cost/Ft. of Oil Wells	$55.59	$12.97	$11.68	$117.42
6. Proved Reserves Added/Ft. of Oil Wells (barrels)	64 b*	24 b	49 b	48 b
7. Av. Drilling Cost Per Barrel of New Proved Reserves	$.69	$.23	$.53	$.78

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* Most favorable ranking among all regions.

__Conclusions:__ Based on our analyses, the Gulf of Mexico stands out as the most attractive lower 48 region for natural gas exploration. Probable potential supply -- discoverable gas in existing fields which has not been proved -- is highest in the Gulf and South Louisiana and South Texas. Current levels of natural gas production in the Gulf can be sustained for another 50 years from estimates proved and provable reserves. This compares to only about 15 years for the Southwest and South Louisiana and South Texas. Finally, drilling costs are only a little higher in the Gulf than the Southwest and substantially lower than South Louisiana and South Texas. We anticipate high interest in exploration, both in existing fields, especially in the near term, and in new fields to tap estimated reserves.

The Gulf does not emerge as sharply as the most attractive region for future oil exploration based on our analysis. We nevertheless conclude that it is at least as attractive as the West -- the most promising lower 48 onshore region -- in the near to mid-term. In the long term, discoverable reserves in the West greatly exceed those in the Gulf. The West, however, ranks low in the natural gas reserves; probable potential supply is only 23 trillion cubic feet, compared to 57 trillion cubic feet in the Gulf. The joint-product characteristic of the Gulf reinforces its attractiveness for exploration.

Other offshore regions have not been discussed because data for most measures are not available. The Pacific Coast has an estimated 48 billion barrels of discoverable oil, almost twice as much as the Gulf of Mexico. The Pacific Coast has very low natural gas reserves however. Probable potential supply is estimated at 1 trillion cubic feet compared to 57 trillion cubic feet for the Gulf. The joint-product character of the Gulf suggests it will remain the most promising offshore region for exploration for some time. Producers already are experienced in drilling and producing operations in the Gulf, and transportation and refining facilities are currently accessible. In contrast, the Pacific Coast retains the nature of a "frontier", to be explored and developed as more easily accessible reserves are diminished. The Atlantic Coast is characterized by even less exploratory experience. Total oil and natural gas reserves are not great, but some areas have favorable structures which probably will be developed in the long term.

Alaska also represents a very promising "frontier." Alaska is estimated to have greater reserves of discoverable oil and natural gas than any lower 48 region. About 31 percent of total discoverable oil reserves and 32 percent of discoverable natural gas reserves lie in Alaska. The Gulf of Alaska is the industry's top priority among "frontier" OCS areas under consideration for leasing in 1975. Operating equipment which can sustain ice flows and Arctic weather must still be developed. In the long term, Alaska may become a major source of domestic oil and gas production.

Trade-off of Exploratory Activity Among Competing Onshore and Offshore Regions

A review of exploratory activity by region from 1966 to 1972 (or 1973, where data are available) supports our conclusion that the West and the Gulf of Mexico are the most attractive regions for future oil and natural gas exploration. The West made the most substantial gains in exploratory activity during this period. The West (principally Pad IV) experienced:

- The greatest increase in the share of exploratory wells and drilling footage;

- The only increase in the absolute number of exploratory wells and drilling footage;
- A modest gain in the share of total and exploratory drilling expenditures.

Within the West, the states which made the greatest gains in exploratory drilling footage in 1972 over 1966 were Colorado, Montana, and Wyoming. Most significantly, no other major producing states in the West, Southwest, or South Louisiana and South Texas showed an increase in exploratory drilling footage in 1972 over 1966.

For the U.S. as a whole, both the number and footage of exploratory wells declined during this period, at compound annual rates of -3.7 percent and -3.8 percent respectively. Thus, for most onshore regions, not only was their share of exploratory activity declining, but the total "pie" was also diminishing in size. Only the West, among major producing regions, increased both its share of exploratory activity and absolute amount during this period. In 1966, the West had 18.0 percent of total exploratory drilling and by 1972, its share had increased to 27.2 percent. The Southeast also gained in the share of exploratory activity during this period; exploratory drilling footage increased from 6.2 to 8.2 percent. It still does not represent a major producing region, however. In 1966, the only state with significant exploratory drilling in this region was Mississippi; by 1972, exploratory interest had focused on Alabama and Florida as well.

A review of expenditures during this period shows the same trends. Total U.S. exploratory drilling expenditures (in constant dollars) in 1972 were only 87.4 percent of their 1966 level. Only in the West and Southeast did 1972 exploratory drilling expenditures exceed 1966 expenditures.

We also conclude that the Gulf has gained in exploratory activity relative to onshore regions, but the conclusion is not as immediately visible from the data as for the West. One difficulty in assessing the data is that exploratory activity in the Gulf and other offshore regions is closely tied to the volume and timing of Federal lease sales. The peak year for exploration in the Gulf was 1968; this followed a Federal lease sale of .7 million acres, the second largest sale held in the Gulf to that date. In 1968, the Gulf's share of exploratory drilling footage reached 8.6 percent, contrasted with 7.1 percent in 1966 and 5.4 percent in 1972.

Second, on a region by region basis, only the West and Southeast showed increases in exploratory activity. But the Gulf shows a lower decline for some measures than other major producing regions or the U.S. as a whole. For example, the number of exploratory wells drilled in the Gulf from 1966 to 1973 declined at a compound rate of -3.1 percent, compared to -3.7 percent for the total U.S. and -5.4 percent for the Southwest. (The compound rate of increase for the West was +0.6 percent.) While the Gulf decreased its share of exploratory drilling expenditures between all offshore and all onshore regions between 1960 and 1972. (Offshore activity predominantly reflects drilling in offshore Louisiana.) On every measure, onshore activity has declined and offshore has increased, as shown in Table 4.

TABLE 4

SUMMARY OF THE TRADE-OFF OF DRILLING ACTIVITY
BETWEEN ONSHORE AND OFFSHORE REGIONS,
1960 TO 1972

Measures of Drilling Activity	Offshore 1960	Offshore 1972	Offshore Compound Rate of Change	Onshore 1960	Onshore 1972	Onshore Compound Rate of Change
No. of Wells Drilled	538	993	+4.6%	43,595	25,450	-5.5%
Footage Drilled (000)	5,608	10,000	+4.1%	180,772	125,535	-4.0%
Expenditures (000000)*	$ 200.9	$ 435.5	+6.8%	$ 2,146.3	$ 1,491.6	-4.1%

---

* In constant dollars using the GNP deflator; 1958 = 100.

Offshore drilling expenditures showed the greatest rate of increase -- +6.8 percent during this 12 year period -- contrasted with a decline of -4.1 percent for onshore drilling expenditures. On the basis of this longer term analysis, we conclude that offshore regions have gained in the share of exploratory activity relative to onshore regions. This trend can be expected to accelerate and the previous peak offshore exploration year of 1968 may soon be surpassed if the Interior Department implements plans to lease 10 million OCS acres by 1975. Until 1973, OCS leasing was under one million acres annually. Even at the previously revised rate of leasing 3 million acres per year, strong exploratory gains offshore can be expected. Exploratory activity overall is expected to reverse its downward trend in 1974. The onshore regions which will benefit most by the increase will be the West and Southeast on the basis of our analysis.

Our review of the effects of leasing policies and other supply controls focused on their impact on the historical distribution of exploration between offshore and onshore regions. With regard to OCS leasing policies, it is not evident that offshore operations would have accelerated more rapidly up to now in the absence of lease constraints. The industry has devoted about one-fourth of total drilling expenditures to offshore drilling in recent years -- a very large commitment of funds. Even so, almost 70 percent of OCS acreage leased has been returned to the government or is being held for future exploration and only 18 percent is classified as productive. Leasing policy has, however, impacted on the distribution of exploration among offshore regions, tending to favor the Gulf and restricting operations in offshore

California. Public land leasing has had no impact on the distribution of exploratory activity, because most leases are obtained at the initiative of the operator.

Review of the conservation regulations of Louisiana, the state with the greatest share of offshore operations, suggests that they impact on the distribution of exploratory activity by tending to promote relatively high cost opportunities -- very deep or very shallow wells onshore, stripper wells whose production is exempt from controls, and offshore wells. Production allowables offshore are higher for any well depth than onshore, ranging from about 50 to 100 percent greater. The attractiveness of offshore operations is illustrated by production history; production offshore increased from about 23 percent of total output in 1960 to 52 percent in 1972 in Louisiana. (This also reflects depletion of older onshore fields.)

The impact of Federal controls cannot be considered independently. Import policy has generally curtailed domestic exploration. Coupled with production restrictions stemming from market demand prorationing and the depletion allowance -- whose value depends on the volume of production which in turn depends on allowables established by conservation regulations -- offshore operations and high cost onshore operations probably have been encouraged at the expense of lower cost onshore opportunities. FPC regulation of natural gas prices probably has not impacted greatly on the production of associated gas which was produced if found incidentally in the search for oil. For the growing share of non-associated gas, prices below market value will restrict the share of natural gas exploration in high cost areas -- offshore, Alaska, and for deep onshore reserves.

The Effects of Government Policies, Economic Conditions, and Cost Factors on the Exploration Decision

We hypothesize that, under a reasonable range of Federal policy alternatives, economic conditions, and costs, the Expected Present Value (EPV) of the typical offshore site will remain positive. That is, government policies have no impact on the decision to explore domestic offshore versus onshore regions; instead they affect only the size of the bonus payment.

In the base case, which we define as a typical, 5,000 acre tract operation in the Gulf of Mexico, the Expected Present Value is $.20 per equivalent barrel -- equal to an average bonus payment of $2,538 per care.*/ The value for each variable used in the base case for the typical offshore field (and for an onshore field selected for comparison purposes) is shown in Exhibit 1.

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*/ This bonus payment falls within the range of average per acre bids in three previous OCS lease sales. The range in average bids per acre was $2,018 to $3,108.

EXHIBIT 1

VALUES FOR EACH VARIABLE AND THE EXPECTED PRESENT VALUE FOR THE TYPICAL OFFSHORE FIELD IN THE BASE CASE AND JAY FIELD

Category	Variable	Typical Offshore Field	Jay Field
Tax and Leasing Policies:	Corporate tax rate (c)	.50	.50
	Rate of percentage depletion (d)	.22	.22
	Royalty rate (r)	.167	.125
	Fraction of dry hole costs which can be expensed immediately (f)	1.00	1.00
	Fraction of exploratory and development well costs which can be expensed immediately (x)	.72	.40
Economic Conditions:	Cost of capital (I)	.08	.08
	Price per equivalent barrel of output (P)	$5.38	$5.41
Characteristics of the Potential Drilling Site:	Probability of commercial production (Y)	.30	.11
	Decline rate (A)	.06	.07
	Operating costs per barrel of output (O)	$.75	$.50
	Wells drilled per barrel of recoverable reserves (B)	$.55\mathrm{x}10^{-6}$	$.24\mathrm{x}10^{-8}$
	Weighted average costs per well of exploration and development costs (W)	$\$.7\mathrm{x}10^{6}$	$\$1.15\mathrm{x}10^{6}$
	Dry hole costs per barrel of recoverable reserves (H)	$.09	$.01
	Recoverable reserves (R)	63,450,280	378,000,000
Expected Present Value:	Per Barrel	$.20	$.10
	Per Acre	$2,538	$1,222

Four sensitivity analyses were developed to test our hypothesis. These analyses reflect adverse conditions which may occur:

- In the area of tax policy, elimination of percentage depletion and expensing of intangible drilling costs;
- In the area of economic conditions, a twenty percent fall in the price of hydrocarbons;
- In the area of operating costs, a 50 percent increase in exploratory and developmental well costs, coupled with a 33 percent increase in operating costs and a 44 percent increase in dry hole costs; and,
- The most adverse case, combining the three changes listed above simultaneously.

In the first three cases, the Expected Present Value of the typical offshore drilling site remains positive, but declines by 35 to 50 percent from the Expected Present Value calculated for the base case. When all three changes are considered simultaneously, the Expected Present Value does become negative. The results are summarized in Table 5. Thus, the only set of policy, conomic, and cost changes which would lead to a negative Expected Present Value is an unlikely combination of severe tax, price, and cost changes. Even under these conditions, while the typical tract defined by our base case would no longer attract bidders, some tracts with more favorable than average characteristics probably would continue to have positive Expected Present Values.

We conclude that our hypothesis has been upheld. Under a reasonable range of public policy, price, and cost conditions, only the amount of the bonus payment will be affected -- not the offshore/onshore exploration decision. Offshore exploration remains more attractive because of more favorable prospects for discovering substantial oil and gas reserves offshore. Thus, operators can be expected to bid for drilling rights on all offshore tracts available for lease.

The four sensitivity analyses we conducted do not cover every possible adverse case in each area of policy, price, and cost changes, but we feel that the results of these simulations represent a sufficiently wide range of alternative scenarios to demonstrate that the decision to bid for offshore drilling rights can only be affected by a combination of adverse effects. Many other sensitivity analyses could be computed, but we believe our conclusions would not be altered. Tax policy changes can only be expected to reduce the amount of the bonus payment. Similarly, environmental regulations which increase operating costs or change the relative price structure among alternative energy sources also would reduce bonus payments, without influencing the decision to operate offshore.

TABLE 5

THE EFFECT OF THE FOUR SENSITIVITY ANALYSES ON THE EXPECTED PRESENT VALUE PER BARREL AND LEASE BID PER ACRE*

Assumptions	Expected Present Value Per Barrel of Reserves	Average Lease Bid Per Acre	Percentage Decreases From Base Case
Base Case	$.20	$2,538.00	-
Sensitivity Analyses:			
(1) Elimination of percentage depletion and expensing of intangibles	.10	1,289.00	50%
(2) Twenty percent price decline	.12	1,523.00	40%
(3) A 50 percent increase in exploratory and developmental well costs, a 33 percent increase in operating costs, and a 44 percent increase in dry hole costs.	.13	1,650.00	35%
(4) Numbers (1), (2), and (3) simultaneously	-.05	-	-

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* Assumes a typical tract of 5,000 acres with ultimate recovery of 63,450,280 equivalent barrels of oil and gas.

No attempt was made to define a "typical" onshore field, because costs of onshore drilling vary greatly between fields. Instead, the Jay Field in Florida was selected for analysis because it is one of the few new giant field discoveries onshore and thus it provides an appropriate comparison for the typical offshore field. The Jay Field, however, probably is more profitable than most onshore operations, so the Expected Present Value obtained using our analysis will reflect a very attractive onshore opportunity, not a typical onshore site.

The Expected Present Value of the Jay Field is $.10 per barrel, or $1,222 per acre. That is, our analysis suggests that a firm would have been willing to pay a bonus up to $1,222 per acre for the Jay Field in a lease sale, based on assumptions about the field which closely approximate actual conditions. Thus, even this very successful onshore field appears less attractive than the typical offshore field.

The Expected Present Value obtained is, of course, very sensitive to key assumptions about the drilling site. One of these is the probability of commercial production. For the typical offshore field, this was assumed to be .30, which reflects historical drilling experience in the Gulf, and it is assumed to be .11 for the Jay field, which represents the typical onshore rank wildcat drilling success ratio. Using .30 for the Jay Field, as well, increases its present value to $.30 per barrel or $3,666 per acre.

Analysis of the impact of adverse policy and economic factors on the decision to explore tracts for which lease bonuses already have been paid is beyond the scope of this study. We focus on the decision to acquire onshore and offshore drilling rights for future exploration. A brief consideration of the issue leads us to conclude that cost increases resulting from adverse conditions after the leases were obtained probably would not significantly reduce exploration of these tracts. In such a case, the bonus payments were made based on a higher Expected Present Value than exists under the new policy and economic scenario. But such bonus payments represent sunk costs to the producer, so that exploration and development remain preferable to abandoning the leased tracts, as long as anticipated reserves are believed sufficient to cover variable costs and make some contribution to overhead. If price expectations also are revised upward subsequent to payment of the bonus, the Expected Present Value may not be reduced.

An equity issue also is raised if the adverse conditions result from changes in public policy. For example, revision of required environmental safeguards which increase costs after lease bonuses are paid on the basis of a different set of expected costs, is equivalent to changing the rules of the game after play has started. However, since price expectations also are likely to be revised upward subsequent to payment of the bonus, the Expected Present Value may be diminished only slightly or not at all. Procedures for renegotiation or refund of the bonus payment might be established, in the event that regulatory action increases costs to the point where the Expected Present Value is significantly reduced.

We also reviewed the impact of factors on the offshore exploration decision which were not amenable to quantitative analysis using our simulation model. These factors include state conservation regulation, the gas-oil ratio, the co-location of refineries and pipelines, and the rate at which offshore tracts are offered for lease. We conclude that reasonable qualitative judgment regarding each of these areas suggests that no negative impact on the rate of offshore exploration can be expected from any of these factors, except for restricting the amount of offshore acreage offered for lease.

Environmental Hazards and Safeguards

Environmental hazards to be anticipated from oil and gas exploration and production on and offshore are well documented. Offshore, major hazards are the impact on the marine environment of routine or accidental oil spills or spillage of sewage and other debris. Onshore, spillage of oil may damage the land or inland waters and the disposal of brines produced with oil must be regulated to safeguard land and fresh water quality. The major difference between onshore and offshore operations is that the possibility of a catastrophic accident resulting in the spillage or large quantities of oil is much greater offshore. This is due to many factors, including: (1) conditions of the offshore environment, such as the likelihood of severe weather and collisions with vessels; (2) location of many wells on one drilling rig; and (3) the logistical difficulties of containing and cleaning up a spill once it occurs. A mitigating factor has been to require operators to install automatic or remote controlled sensory devices on offshore drilling and transportation equipment.

As a guide to evaluating the relative hazards of exploration and anticipated production among regions, we identified seven high risk characteristics which suggest a greater than average probability of environment damage:

- The extent of existing oil and gas operations.
- Delicate ecology.
- Severe climate or extreme variations in weather.
- Extensive use of equipment based on new technology.
- Existence of food industry (farming, fishing) or commercial shipping in areas to be drilled.
- Offshore operations generally.
- Extensive use of area's water supply (in reference to secondary recovery operations).

These and other characteristics could be further refined to develop a useful analytical tool. Also, weights could be assigned to each characteristic according to degree of risk, so that regions can be ranked according to composite "scores". We did not weight the characteristics but, generally, the extent of existing operations is one of the most important characteristics. This results from several factors:

- there is a short-term but unavoidable one-time impact associated with many operations such as laying pipelines or constructing storage facilities,
- familiarity with operations in a particular region can be expected to reduce the rate of accidents, and
- the possibility that large scale development, e.g., the the construction of refineries, petrochemical complexes, gas processing facilities and accompanying impacts on the local economy, may result in environmental degredation, particularly in areas which currently are not characterized by extensive industry or familiarity with land use planning.

Various Federal, state, and local government agencies regulate oil and gas operations in the interests of protecting the environment. The Interior Department has major authority for regulating operations on the Outer Continental Shelf, as mandated by the Outer Continental Shelf Lands Act. Onshore operations and offshore operations in state waters are regulated by state conservation agencies and the Interior Department also regulates operations on onshore public lands. In addition, various other agencies have authority to prescribe regulations which impact on offshore and onshore operations in the interest of safeguarding wildlife, marine flora and fauna, commercial fishing, shipping, and air and water quality.

The Environmental Protection Agency has a major role in insuring that oil and gas operations do not endanger the environment. EPA's authority stems primarily from two laws: (1) the National Environmental Policy Act and (2) the Water Quality Improvement Act. Since the passage of the National Environmental Policy Act, impact statements have been prepared for all Federal OCS lease sales. The effect has been to allow public review of proposed sales and to cause the Interior Department to require various safeguards as a condition of obtaining the leases, to prevent against environmental damage which the impact studies identified.

Under the Water Quality Improvement Act, the Environmental Protection Agency is authorized to establish requirements for prevention and clean-up plans of oil spills required for all facilities engaged in producing oil in locations where oil discharges might damage U.S. waters or shorelines. Since the most severe damage offshore would result from a catastrophic equipment failure due to damage by ships or storms, effective prevention and clean-up plans are essential. EPA's final requirements were issued in December, 1973.

Conclusion

Our analyses suggest that the Gulf of Mexico remains the most attractive lower 48 region for hydrocarbon exploration in the near term. Characteristics of the Gulf which highlight its "intrinsic desirability" for future hydrocarbon exploration are:

- large remaining reserves of oil and gas,
- the expectation of high exploratory drilling success rates,
- joint-product nature of many operations,
- abundant transportation and other support facilities,
- long-term producer experience -- at least in waters less than 600 feet deep -- and mild weather conditions relative to the Atlantic and Alaskan OCS.

Other offshore regions -- the Atlantic OCS, the Pacific OCS, and offshore Alaska -- also appear very promising but data limitations did not permit detailed comparisons of these offshore regions with the Gulf and lower 48 onshore regions.

Expansion of the domestic supply of oil and natural gas requires acceleration of production from offshore areas. The Interior Department's proposal to lease ten million OCS acres by 1975 will require large lease sales in the Gulf and other offshore areas. Future sales in the Gulf can be expected to include more deep water acreage, since production in deep waters was not technically feasible until recently and only one previous Gulf sale has offered deepwater acreage. Most Gulf production today is in offshore Louisiana. Louisiana has 16 million acres offshore to 600 feet and 4.1 million of these currently are under lease. A total of nine million acres have been offered for lease to date. Only one lease sale has been held offshore Louisiana, Alabama, and Florida, and a relatively small percent of offshore Texas is under lease.

The CEQ report on offshore production in the Atlantic and Alaskan OCS recommended that Atlantic oil fields be developed first due to environmental considerations. The Interior Department, however, expects the Gulf of Alaska to be the first of the two areas in which lease sales will be held, because of legal issues concerning the Atlantic coastal states' jurisdiction over offshore territory.

Lease sales offshore California also can be anticipated since the five year ban on drilling has been lifted. Generally, the volume of exploration can be expected to reverse its downward trend in 1974 and exploration will increase most rapidly offshore -- and in the West. Further offshore exploration can be expected to continue at high levels in the Gulf but to focus on other offshore areas also.

Given this surge of exploration and its probable distribution, we recommend that EPA address the following areas to insure that environmental issues are adequately resolved.

1. The Interior Department proposes leasing 10 million acres annually by 1975 on the Outer Continental Shelf and Slope. Through 1973, only about one million acres were leased annually. Concern has already been expressed about whether this huge volume of acreage could be leased on such short notice and provide a fair return to the government and equitable opportunities for operators under the present system of leasing. The lease sales could simply become a contest among majors as to which could raise the maximum capital in a short-time period. The government would not have sufficient time to appraise the value of the tracts and environmental impact of alternative sites to assess whether bids should be rejected. Senator Bentson (D.-Texas) has said that we will introduce legislation to substitute the present system with a direct government/operator profit sharing system. The Interior Department has restructured its procedure for nominating tracts to be leased and plans to forbid joint bidding by the ten largest firms and improve its bid rejection system. Other proposed legislation would reorganize Federal agencies' responsibilities for environmental aspects of OCS production. However, opponents of this legislation suggest it may lead to more duplication of effort and lessen the comprehensive treatment under existing authority. EPA should evaluate the environmental impact statement process, to determine if it can be maintained at its current (or an improved) level of quality if OCS lease sales are rapidly accelerated.

2. As offshore operations accelerate and are introduced into new areas, the prevention and clean-up plans requirements for offshore operators should be reviewed and made more stringent if necessary. At prices of $5.00 and higher per barrel for oil, we estimate ample funds are available to implement any desirable contingency measures. For new leases, if bonus bids are retained, bonus payments will be lower to reflect anticipated implementation costs. On old leases, bonus payments were based on lower prices, so some portion of the price increase is available to finance environmental safeguards not required at the time the lease was obtained.

3. At higher price levels, alternatives to oil and gas might become economic (oil shale, tar sands, coal gasification, etc.). The environmental impact of these alternatives relative to increased hydrocarbon production offshore, in the West, and Alaska should be evaluated. One alternative to increasing production offshore which may become important in the near term is vastly expanded use of secondary recovery operations onshore. On the average, 8.62 barrels of water are required to produce one barrel of oil using water injection.* Brines produced along with oil are adequate in quantity to meet most water demands of secondary recovery operations. If secondary recovery operations are greatly expanded, however, addi-

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* Estimates are that about 1.10 to 1.25 barrels of the water required for water injection must be obtained from local surface or ground waters.

tional large demands on the region's water supply may result. This issue has not been the subject of previous study. Under current legislation, state conservation agencies are responsbile for regulating secondary recovery operations. If a problem of national scope emerges, legislation could be proposed to provide a role for EPA to assist the states in dealing with this problem.

4. Underlying all concerns regarding environmental protection in light of the future expansion of domestic energy supplies is the need to promote energy conservation. A fundamental change in consumer values is needed. EPA should promote reduced consumption of energy from all sources as a primary means of environmental protection.

II

ANALYSIS OF OIL AND NATURAL GAS RESERVES IN ONSHORE AND OFFSHORE REGIONS

Methodology

The regions used in this study are based on a consolidation of the twelve areas developed by the Potential Gas Committee. Five of these twelve include offshore areas. For this study, we consolidated the twelve onshore areas into six regions and the five offshore areas into four regions. The map on the following page illustrates the regions used in this study.

The PGC areas were used as a basis for the development of the ten regions used in this analysis for several reasons:

- Potential gas reserves estimated by the PGC according to these 12 regions are referred to frequently in this study and are not easily adjustable to other regional areas.
- The PGC regions generally include entire states (or R. R. communication districts for Texas), so that API and AGA reserve estimates and other data reported on a statewide basis can easily be converted to PGC regions. The NPC petroleum provinces, in contrast, generally do not follow state boundaries.
- Reserves of both oil and natural gas tend to be distributed similarly among regions, so using the PGC regions for both resources is appropriate.

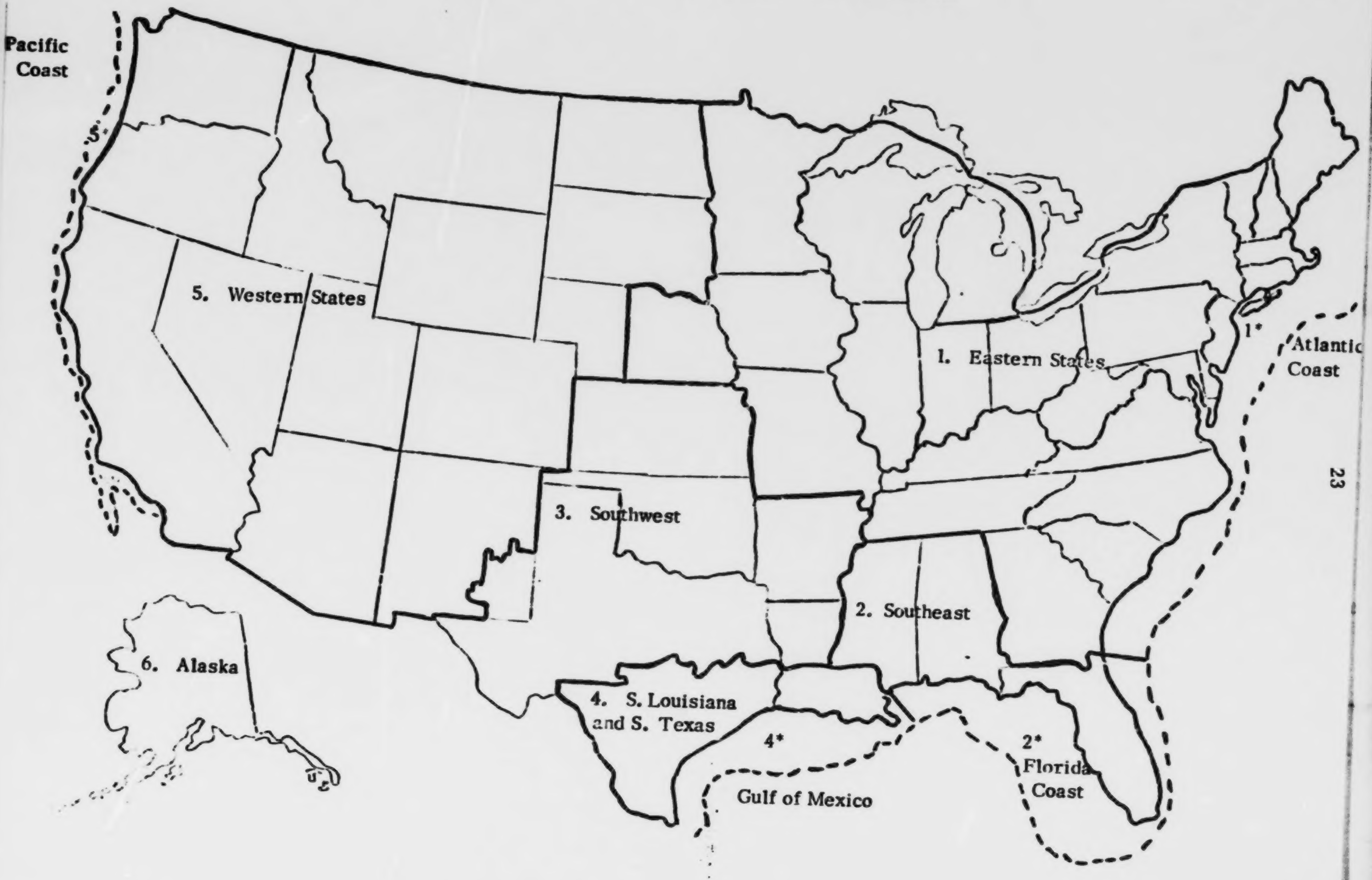
The six onshore regions are:

- Region 1 -- Eastern United States
- Region 2 -- Southeastern United States
- Region 3 -- Southwestern United States
- Region 4 -- South Louisiana and South Texas
- Region 5 -- Western United States
- Region 6 -- Alaska

The four offshore regions are:

- Region 1* -- The Atlantic Coastline north of Florida

REGIONS USED FOR THE COMPARATIVE ANALYSIS


Pacific Coast
5*
5. Western States
3. Southwest
6. Alaska
4. S. Louisiana and S. Texas
4*
Gulf of Mexico
2. Southeast
2*
Florida Coast
1. Eastern States
1*
Atlantic Coast

- Region 2* -- Offshore Florida, Mississippi, and Alabama
- Region 4* -- The Louisiana and Texas Gulf Coast (referred to in the text as the Gulf of Mexico)
- Region 5* -- The Pacific Coast

Appendix 3 lists the states and subdivisions of states included in the lower 48 onshore regions.

Evaluation of the Attractiveness of Onshore and Offshore Regions

The purpose of this analysis is to assess the relative attractiveness for future exploration of onshore and offshore regions based upon their geological characteristics. Other factors which impact on the decision of where future exploration will occur, e.g., government policies and regulations, economic conditions, the location of transportation and processing facilities, etc., are evaluated in Chapter 3 of this study.

Our assessment of which regions appear to have the most favorable geology is based on two major categories of information:

- Reserves of oil and natural gas discovered and remaining to be discovered; and

- Success and cost of past exploratory and developmental drilling.

Data limitations constrain this analysis. Data were required in sufficient detail to allow the onshore and offshore regional comparisons. The major constraint was that the Gulf of Mexico is the only offshore region for which most of the data we assess are available:

- The American Petroleum Institute (API) compiles separate offshore statistics only for the Gulf of Mexico. Data for offshore California are included in the state total.

- The American Gas Association (AGA) publishes no statistics on offshore areas except proved reserves and ultimate recovery for the Gulf of Mexico.

- Since virtually no exploratory drilling has been conducted in the Atlantic Coast and the Florida Gulf Coast, the only reserve estimates regularly compiled for these regions are the future potential supply of natural gas by the Potential Gas Committee (PGC). The entire estimate is classified "speculative" (least likely to be discovered).

Based on these and other data constraints, we identified twenty-five indicators which suggest whether the prospects for future exploration in a region appear favorable or unfavorable. Each indicator provides some relevant information about the region's geology. They are listed in Chart 1 on the following page. Chart 1 also indicates whether the numerical value of the indicator must be "high" or "low" for the region to receive a favorable assessment. For example, a favorable rating requires a high estimate of proved reserves relative to other regions, but the cost per foot of drilling requires a low value for favorable assessment. An optimal hypothetical region assessed in this manner would be characterized by highest discovered and discoverable reserve estimates, shallowest wells, lowest costs per foot of drilling, and highest success rates for all types of exploratory drilling.

After compiling the data, we ranked the regions according to the value obtained for each indicator. A total of twenty-five rankings were obtained. (These are shown in Appendix 2.) Our final assessment of the relative attractiveness of the Gulf of Mexico (and other offshore regions where data are available) versus onshore regions is based on three further steps:

- Determination of the frequency that the Gulf of Mexico was ranked favorably -- among the top three regions -- for all the indicators;
- A selective look at the magnitude of indicators for the Gulf of Mexico to determine whether the Gulf's regional rank only partially reflects its attractiveness. For example, the Gulf ranks first in proved reserves added per foot of oil wells drilled. Additionally, the value for the Gulf is almost one-third larger than the region ranked second and more than twice as great as the regions ranked four through six; and
- An assessment of the relative importance of selected indicators.

Discoverable Oil Resource Estimates

Estimates of the amount of remaining discoverable oil are available from numerous special studies conducted by agencies of the Department of Interior and private organizations. Such estimates are not made by the API or other industry groups.

A note of caution must be introduced at the outset regarding the limitations of discoverable reserve estimates. Regardless of the methodology employed, all discoverable reserve estimates are highly tenuous because they are based largely on unknown resources. That is, no drilling experience is available to verify the existence of estimated discoverable reserves. Discoverable reserve estimates thus vary greatly and no estimates from different sources are directly comparable because of the different assumptions on which they are based. Generally, two types of methods have

CHART 1

INDICATORS USED TO ASSESS THE STATUS OF COMPETING ONSHORE AND OFFSHORE REGIONS

Indicators	Attractiveness If Numerical Value is:
Oil Reserves:	
1. Proved Reserves, 1972	High
2. Discoverable Resources, 1972	High
3. Ultimate Receovery as Percent of Original Oil-in-Place, 1972 (oil in known reservoirs which can be produced)	High
4. Cumulative Production as Percent of Ultimate Recovery, 1972 measures the depletion of proved reserves	Low
5. Reserve/Production ratio, 1972	High
Natural Gas Reserves:	
1. Proved Reserves, 1972	High
2. Total Potential Supply, 1972	High
3. Probable Potential Supply, 1972	High
4. Potential Supply-less than 200 meters deep offshore or 15,000 feet onshore only, 1972	High
5. Ultimate Recovery as Percent of Ultimate Discovery 1972 (measures degree to which discoverable reserves have been proved and produced)	Low
6. Cumulative Production as Percent of Ultimate Recovery, 1972	Low
7. Reserve/Production ratio, 1972	High
Drilling Statistics:	
1. Average cost/foot of Oil Wells Drilled, 1971	Low
2. Average cost/foot of Gas Wells Drilled, 1971	Low
3. Average Drilling Cost per Barrel of New Proved Oil Reserves, 1971	Low
4. Average Drilling Cost per Million Cubic Feet of New Proved Natural Gas Reserves, 1971	Low
5. Average Depth of Total Oil Wells, 1972	
6. Average Depth of Total Gas Wells, 1972	
7. Proved Reserves Added per Foot of Oil Wells Drilled, 1972	High
8. Proved Reserves Added per Foot of Gas Wells Drilled, 1972	High
9. Average Depth of Exploratory Oil Well Drilled, 1971	Low
10. Average Depth of Exploratory Gas Well Drilled, 1971	Low
11. Success Rate of All Exploratory Wells, 1971	High
12. Success Rate of New Pool Wildcats, 1971	High
13. Success Rate of New Field Wildcats, 1971	High

been used to derive discoverable reserve estimates:

- Geological methods, based on expectations of hydrocarbons found in known geological strata and assumptions about finding rates, and
- Mathematical methods, based on extrapolating historic exploration trends.

Even estimates based on the same general method are not comparable. Factors which differ frequently among geological estimates are the area and depth of favorable strata included in the analysis. For example, PGC estimates are based on favorable strata to 30,000 feet in depth whereas NPC estimates are based on depths only to 20,000 feet. While an attempt is made in this chapter to identify reasons for large differences in estimates and to suggest what a reasonable range of discoverable reserves appears to be, the uncertainty underlying all estimates is so great that an attempt at precise reconciliation would be meaningless.

The most recent estimate of the discoverable current inventory of oil was developed by the National Petroleum Council (NPC). The NPC estimates that the United States has 385 billion barrels of discoverable oil, distributed as follows:

- 177 billion barrels -- lower 48 onshore
- 89 billion barrels -- lower 48 offshore
- 119 billion barrels -- Alaska.

Thus, the lower 48 offshore regions are estimated to contain about one-fourth of discoverable oil.

Table 6 shows how the NPC estimate compares to five other recent estimates, including an earlier (1970) NPC estimate. The NPC's 1972 estimate is 53 billion barrels greater than the 1970 estimate. This primarily reflects an upward reappraisal of reserves in the Alaskan North Slope and new estimates for portions of the Alaskan continental shelf. NPC estimates are based on a variety of geological methods including extrapolation and interpolation along trends, comparison of similar areas and strata, evaluation of structures determined by geophysical prospecting, evaluation of the undrilled parts of known fields and pools, and assignment of overall oil incidence to rock volumes. The NPC report does not cover all favorable strata. The results, though conservative, represent the most detailed estimate of discoverable crude oil made to date.

The estimates made by the United States Geological Survey (USGS) are developed by applying historical results of past exploratory drilling to unexplored rocks on an

TABLE 6

ESTIMATES OF DISCOVERABLE OIL FOR THE UNITED STATES
(Billions of Barrels)

Estimates	United States, Total	By Area: Lower 48 Onshore	Lower 48 Offshore	Alaska
National[1] Petroleum Council, 1972	385	177	89	119
National[2] Petroleum Council, 1970	332	--	--	--
U. S. Geological[3] Survey, 1972	450	230	120	100
U. S. Geological[4] Survey, 1965	459	353		106
Bureau of[5] Land Management, 1970	640	480 (all other U. S.)	110 (OCS)	54 (OCS)
Moore, C. L., 1970[6]	353	NA	NA	NA

Footnotes are shown on the following page.

Footnotes to Table 6

1. U. S. Energy Outlook, National Petroleum Council.

   December, 1972, p. 72. Previous estimates were updated to reflect developments on the Alaskan North Slope, Alaskan Continental Shelf and others. Oil discoverable after 1970 is increased by 53.3 billion barrels.

2. Future Petroleum Provinces of the United States. National Petroleum Council.

   July, 1970. Based on a geological analysis of the U. S. onshore, continental shelf and continental slope. Discoverable reserves are shown in two categories: probable and potential (based on the AGA definitions) and speculative. The total is obtained by adding all probable and possible (227/bb) and one-half of speculative (209/bb) resources.

3. Theobold, P. K., Schweinfurth, S.P., and D.C. Duncan. Energy Resources of the United States, U. S. Geological Survey Circular 650, 1972. Recoverable undiscovered resources are estimated by updating previous USGS figures (Hendricks, 1965; Hendricks and Scheinfurth, unpublished data 1966; McKelvey and others, 1969; Scheinfurth, unpublished data, 1971).

4. Hendricks, T. A., Resources of Oil, Gas and Natural Gas Liquids in the United States and the World, U. S. Geological Survey Circular 522, 1965. Resources estimates are derived by applying the historical results of past drilling to unexplored rocks for all favorable strata of the U. S. including Alaska and the continental margins to 2500 meters. Five-eights of oil-in-place is estimated to be discoverable with current exploration technology.

5. The Role of Petroleum and Natural Gas from the Outer Continental Shelf in the National Supply of Petroleum and Natural Gas, Bureau of Land Management, U. S. Dept. of Interior. Technical Bulletin No. 5, May 1970, p. 49. Estimate of potential recoverable crude oil resources is obtained by applying a 40 percent recovery rate to Hendrick's estimate of 1600 billion barrels of crude oil in place. Estimates for lower 48 offshore regions and Alaska are based on McKelvey (In Potential Mineral Resources of the United States Outer Continental Shelves, 1968). Totals do not add due to rounding.

6. Moore, Charles L. in Future Petroleum Provinces, op. cit., p. 198. Resource estimates are derived mathematically; historical patterns of discovery are projected using a Gompertz Curve. Estimates are derived separately for crude oil, natural gas, and NGL.

equal basis for all favorable strata, including the continental margins to water depths of 2,500 meters. The estimate of total oil in place is converted to discoverable oil by applying a finding factor of five-eights and to recoverable oil by applying a recovery factor of 40 percent to discoverable oil. The 1972 USGS estimate is only 9 billion barrels lower than the 1965 estimate and reflects minor reappraisals of the previous estimate.

The USGS estimates include natural gas liquids while the NPC estimate does not. The USGS estimate of discoverable natural gas liquids is 28 billion barrels. Subtracting this from the 1972 USGS estimate results in a comparable USGS estimate of 422 billion barrels -- less than 10 percent greater than the NPC estimate of 385 billion barrels.

The Bureau of Land Management (BLM) estimate of 640 billion barrels is based on the 1965 USGS estimate of oil-in-place, but applies a finding factor of 40 percent. The BLM estimates of offshore and Alaska reserves (Outer Continental Shelf only) are based on work by V. E. McKelvey who used the USGS methodology described above. McKelvey's estimate of 106 billion barrels for the lower 48 offshore areas (outer continental shelf only) falls between the USGS and NPC estimates. However, the BLM estimate of 480 billion barrels for the remaining U. S. is higher than the NPC and USGS estimates for the total U. S.

Moore's estimate was published by the NPC with its 1970 estimate. It is the only estimate shown based on a mathematical model. Historical patterns of discovery were projected for the total U. S.

Thus, the most recent estimates suggest that the range of discoverable oil is about 385 to 422 billion barrels. Both these estimates are based on geological analyses. The USGS estimate assumes that 24 percent is located in lower 48 offshore regions and the NPC places the percentage at 27 percent. These estimates are similar and suggest that probably one-fourth of discoverable oil lies offshore the lower 48 states.

While there is greater consensus on the amount of discoverable oil offshore than onshore, its distribution remains an issue. The BLM estimate of reserves for the total U. S. is much higher than the NPC and 1972 USGS estimates, but the estimate of reserves in offshore areas is similar. Table 7 shows three estimates of how lower 48 discoverable oil is distributed between regions. Regional breakdowns of offshore reserves are available only for the NPC and BLM estimates shown in Table 6 . Additionally, the USGS has recently revised its estimate of offshore reserves downward and, for the first time, shows estimates by offshore region. These 1974 USGS estimates also are shown in Table 7 . The 1974 USGS estimate for total lower 48 offshore reserves is 50-90 billion barrels, contrasted with the 1972 estimate of 120 billion barrels.

The NPC estimates that the Pacific coast has the largest proportion of discoverable oil, 54 percent, while the BLM and USGS estimate that the Gulf has the largest

TABLE 7

ESTIMATES OF DISCOVERABLE OIL IN OFFSHORE REGIONS

(Billions of Barrels)

		Offshore Regions			
Source of Estimate	Total Lower 48 Offshore	Atlantic Coast	Offshore Florida Mississippi, and Alabama	Gulf of Mexico	Pacific Coast
National [1] Petroleum Council, 1972	89	14	N.A.	27	48
Bureau of Land [2] Management (to 200 Meters only), 1970	106	42	N.A.	60	8
USGS, 1974 [3]	50-90	10-20	--	30-50	10-20
Bureau of [4] Land Management, 1973			2-3		
State of [5] California, 1973					1-3

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[1] U. S. Energy Outlook, op. cit., pp. 72 and 73. Offshore Florida, Mississippi, and Alabama estimates are included in Atlantic Coast and Gulf of Mexico estimates.

[2] The Role of Petroleum and Natural Gas from the Outer Continental Shelf in the National Supply of Petroleum and Natural Gas, op. cit., p. 49. Based on McKelvey's estimates in Potential Mineral Resources of the United States Outer Continental Shelves, 1968. Regional totals do not add to lower 48 offshore total in Table due to rounding.

[3] CEQ, OCS Oil and Gas -- An Environmental Assessment, April, 1974.

[4] Estimate published in the "Draft Environmental Impact Statement of Proposed Sale of Oil and Gas Leases off Coast of Mississippi, Alabama, and Florida," July, 1973. Refers only to .9 million acres proposed for leasing.

[5] Energy in California. State of California, Division of Oil and Gas, 1973, p. 22. This estimate is for offshore California only, and appears to be relatively low. The Oil and Gas Journal estimates potential reserves in the Santa Barbara Channel alone at 3/bb. (See Oil and Gas Journal, April 30, 1973, p. 111). The USGS has estimated the Channel's potential reserves at .7 to 1.1 bb. (See Energy Resources Report, July 27, 1973, p. 197.)

proportion, 55 to 60 percent. The proportion believed to be in the Atlantic coast ranges from 16 to 40 percent. The NPC, BLM, and USGS show information for only three offshore areas -- the Atlantic coast, the Gulf of Mexico and the Pacific coast -- so any resources estimated in offshore Florida, Mississippi, and Alabama are included in Atlantic Coast and Gulf estimates.

While no published discoverable oil estimates for offshore Florida, Mississippi and Alabama are available, it is an area of considerable promise. The first lease sale has been held. The acreage leased is estimated to contain 2 to 3 billion barrels of recoverable reserves. The other estimate shown, 1 to 3 billion barrels for the Pacific Coast, was compiled by the California State Division of Oil and Gas and is for offshore California only. However, this estimate appears very conservative. The Oil and Gas Journal estimates that the Santa Barbara Channel alone has potential reserves of 1 to 3 billion barrels.

Discoverable Natural Gas Resource Estimates

The potential supply of natural gas remaining to be discovered has been estimated biannually since 1964 by the Potential Gas Committee, sponsored jointly by industry associations and the Colorado School of Mines. The estimate of potential supply is divided into three categories:

1. Probable -- most likely, resulting from expansion of existing fields.
2. Possible -- less likely, resulting from new field discoveries in formations previously productive.
3. Speculative -- least likely, resulting from new field discoveries in formations not previously productive.

Estimates are developed for eleven lower 48 onshore regions, 5 lower 48 offshore regions, and Alaska. A variety of geological methods are used in preparing the estimates, similar to those used by the NPC. All favorable areas (as identified by the USGS) are included in the estimates. The PGC estimate represents the most detailed effort to determine the amount of discoverable natural gas to date.

As of December 31, 1972, the PGC estimates that the United States has 1146 trillion cubic feet of discoverable natural gas distributed as follows:

- 550 -- lower 48 onshore
- 230 -- lower 48 offshore
- 366 -- Alaska

The lower 48 offshore regions thus contain an estimated twenty percent of potential supply.

The PGC estimate is compared to six other estimates in Table 8 . Both reports published by the National Petroleum Council included estimates of discoverable natural gas based on PGC estimates. The NPC report of 1972 used the PGC estimate current as of December 31, 1970 without modification. The 1970 report published on estimate of 911 trillion cubic feet, which was derived by subtracting one-half of potential supply classified speculative in the PGC estimate current as of December 31, 1968.

Two USGS estimates are shown. The 1965 estimate is derived by applying a gas-oil ratio to estimates of oil-in-place (derivation of oil-in-place was discussed in the preceding section) to obtain a gas-in-place estimate and applying a discovery factor of five-eights. The USGS 1972 estimate updates the previous estimate. The 1972 estimate of 2100 trillion cubic feet is almost twice as great as the PGC estimate of 1146 trillion cubic feet. The BLM estimate of 1900 trillion cubic feet also is substantially greater than the PGC estimate. The BLM estimate of total discoverable natural gas is derived by updating a previous USGS estimate and the estimates for lower 48 offshore areas and Alaska (both Outer Continental Shelf only) are based on work by V. E. McKelvey who used the USGS methodology described previously.

The estimate by C. L. Moore was derived mathematically using the same procedure as for oil -- projection of historic patterns of discovery. At 877 trillion cubic feet, it is the lowest estimate shown. The two most recent estimates -- the PGC and USGS estimates -- of 1146 trillion cubic feet and 2100 trillion cubic feet suggest considerable uncertainty as to the amount of discoverable natural gas. While both include all favorable strata, the PGC estimate is based on a much more comprehensive geological analysis than the USGS estimate, and thus is most frequently used as a reference by industry and other study groups. As we have seen, the NPC published the PGC estimates with its own estimates of discoverable oil.

There appears to be somewhat more agreement with regard to the distribution of discoverable natural gas in offshore areas, although not with the volume. Table 9 shows the distribution of discoverable offshore natural gas for the PGC and BLM estimates shown in Table 8 and 1974 USGS estimates. Most gas is estimated to lie in the Gulf of Mexico -- 65 percent by the PGC, 51 percent by the BLM, and 77 percent by the USGS. However, the estimates are not directly comparable because: 1) the BLM estimate includes the Outer Continental Shelf only; and 2) both BLM and USGS estimates for offshore, Florida, Mississippi, and Alabama are not shown separately but are included in estimates for the Gulf and the Atlantic Coast. All estimates assume that the Pacific Coast has only a minor share of potential reserves -- about 5 percent of the total. The proportion of reserves estimated to lie in the Atlantic Coast ranges from 15 to 41 percent.

TABLE 8

ESTIMATES OF DISCOVERABLE NATURAL GAS FOR THE UNITED STATES
(Trillions of Cubic Feet)

Source of Estimate	U. S. Total	By Area: Lower 48 Onshore	Lower 48 Offshore	Alaska
Potential Gas[1] Committee (1972 Total)	1146	550	230	366
National Petroleum[2] Council, 1972	1178	625	244	309
National Petroleum[3] Council, 1970	911			
U. S. Geological[4] Survey, 1972	2100	1000	620	480
U. S. Geological[5] Survey, 1965	2058	1579		479
Bureau of[6] Land Management, 1970	1900	1122	507	271
Moore, C. L.,[7] 1970	877	N. A.	N. A.	N. A.

Footnotes appear on the following page.

Footnotes to Table 8

1. Potential Gas Committee, *op. cit.*
   Estimates are current as of December 31, 1971.

2. *U. S. Energy Outlook*, *op. cit.*
   PGC 1970 estimates are used without modification.

3. *Future Petroleum Provinces of the United States*, *op. cit.*

4. Theobold, P. K., *op. cit.*
   Previous USGS estimates are updated.

5. Hendricks, *op. cit.*
   Potential resources of natural gas and NCL are determined by applying a gas-oil ratio to estimated quantities of oil (based on applying historical results of exploratory drilling to unexplored rocks) and an NGL gas ratio to the resultant gas estimate. A finding factor of 5/8 is applied.

6. Bureau of Land Management, *op. cit.*
   Estimate of U. S. Total economically recoverable potential supply is based on Hendricks' 1966 estimate in United States Petroleum Through 1980, 1968, and estimates for lower 48 offshore and Alaska are based on McKelvy, *op. cit.*

7. Moore, *op. cit.*
   Historical patterns of discovery and recovery are projected.

TABLE 9

ESTIMATES OF DISCOVERABLE NATURAL GAS IN OFFSHORE REGIONS
(Trillions of Cubic Feet)

		Offshore Region			
Source of Estimate	Total Lower 48 Offshore	Atlantic Coast	Offshore Florida Alabama, and Mississippi	Gulf of Mexico	Pacific Coast
Potential Gas Committee: Total, 1972[1/]	230	35	36	148	11
Potential Gas Committee: Probable & Possible Only, 1972	150	0	0	142	8
Bureau of Land Management[2/]	507	211	NA	258	38
U.S.G.S., 1974[3/]	310-560	55-110		240-425	15-25
Bureau of Land Management, 1973[4/]	NA		2 - 4		
State of California[5/]	NA				1

Footnotes:

[1/] Potential Gas Committee, op. cit.

[2/] Bureau of Land Management, op. cit. p. 125. Based on McKelvey's estimates in Potential Mineral Resources of the United States Outer Continental Shelves, 1968. Includes OCS areas only.

[3/] CEQ, OCS Oil and Gas -- An Environmental Assessment, April, 1974.

[4/] Estimate published in the "Draft Environmental Impact of Statement of Proposed Sale of Oil and Gas Leases off Coast of Mississippi, Alabama and Florida," July, 1973. Refers only to the .9 million acres proposed for leasing.

[5/] Energy in California, op. cit. p. 22. Refers to offshore California only.

The PGC estimates that 36 trillion cubic feet, or about 16 percent of potential supply, are located in offshore Florida, Mississippi and Alabama. No other published estimate of reserves for this region exists. The BLM estimates that reserves in the proposed acreage to be leased range from 2 to 4 trillion cubic feet. Table 9 shows one other estimate -- 1 trillion cubic feet for offshore California only.

We used NPC estimates of discoverable oil and PGC estimates of potential natural gas to conduct our regional analysis because these estimates are based on the most comprehensive geological surveys conducted to date and are generally held to be the most accurate estimates available. Discoverable reserves in new fields will not play a major role in meeting demand in the near to mid-term -- until about 1985. Production will continue to deplete proved reserves, and exploration will focus on developing new proved reserves in the proximity of present producing reservoirs.

A breakdown of discoverable reserves by relationship to current producing fields is necessary to estimate the significance of discoverable reserve estimates for future exploration in the near to mid-term. Such a breakdown is available for natural gas but not oil. The PGC estimate of probable potential supply includes natural gas estimated to lie in existing fields but not yet proved.

Reserves in the proximity of current producing fields are more attractive because of drilling and producing experience, and proximity of transportation, storage, and refining facilities. For example, while the Atlantic coast is credited with substantial reserves of both oil and natural gas by several sources, projections of future production estimate no significant output before 1985. In contrast, the Gulf which has current annual production of about 400,000 barrels of oil, is estimated to reach production of about 1,000,000 barrels of oil by 1985.

U. S. Proved Reserves: Historical Data

A brief review of historical proved reserve estimates for oil and natural gas is presented so that the regional distribution of current estimates can be evaluated in the context of past total reserves. Data on estimated proved reserves have been compiled annually since 1946 by the Committee on Reserves and Productive Capacity of the American Petroleum Institute. The Committee on Natural Gas Reserves of the American Gas Association also has developed proved reserve estimates for natural gas and natural gas liquids since 1946. The methodologies and reporting formats are similar for both. Data are published by states and subdivisions of states, based on reserve estimates for individual fields and reservoirs. In order to maintain the confidentiality of the data, both the API and the AGA have combined reserve estimates for areas in which there are only one or a few fields into another category so that no data for one field or one producer can be derived. Thus, offshore proved reserve estimates for California are included in the state total and estimates for offshore Louisiana and offshore Texas are combined. No other offshore areas have proved reserves. States with few producing fields are combined into a miscellaneous category.

Estimates of proved reserves are not developed by any Federal agency on an ongoing basis. The only independent study conducted to date is the Natural Gas Reserves Study (NGRS) published in 1973 by the Federal Power Commission. Natural gas reserves as of December 31, 1970, were estimated. The NGRS estimate is based on study of a stratified sample of producing fields. All 108 fields with reserves reported to be greater than 400 billion cubic feet were included and 50 of the remaining fields were selected. Reserves in these 158 fields represent about 56 percent of total reserves estimated.

Table 10 shows estimated proved reserves as of December 31, annual reserve additions, net production, and annual R/P ratios for natural gas for the total United States from 1946 through 1972. The Natural Gas Reserve Study estimate of proved reserves for 1970 also is shown. Similar data are shown in Table 11 for crude oil.

The NGRS estimate is somewhat lower than the AGA estimate as of December, 1970: 261.6 and 186.7 trillion cubic feet (186.7 excludes gas in underground storage). The difference of 23.5 trillion cubic feet is less than 10 percent. However, it results in a substantial difference in the reserve/production (R/P) ratio at the end of 1970. Based on AGA estimates, it was 13.1 but it was only 11.9 based on NGRS estimates.

Regional Distribution of Oil Reserves

In order to assess the relative attractiveness of the oil reserves of the 6 onshore and 4 offshore regions, we identified 5 indicators which we believe are useful measures:

1. Proved Reserves -- proved reserves are found in known reservoirs and are estimated to be recoverable under existing operating and economic conditions. High estimates of proved reserves suggest the region is attractive for further developmental drilling and production.

2. Remaining Discoverable Oil-in-Place -- illustrates how much oil remains to be discovered and added to the inventory of proved reserves. High estimates suggest the region is attractive, especially for exploratory drilling in new fields.

3. Ultimate Recovery as a Percent of Original Oil-in-Place -- measures the degree to which oil in known reservoirs is expected to be recoverable. A high percentage suggests that much of the oil in known reservoirs can be produced under existing operating and economic conditions.

4. Cumulative Production as a Percent of Ultimate Recovery -- measures the degree to which proved reserves have been depleted. A low value shows that most proved reserves remain available for production.

TABLE 10

NATURAL GAS: PROVED RESERVES AND PRODUCTION
(Trillion cubic feet)

Year	Reserve Additions	Net Production	Proved Reserves Year End	R/P Ratio
1946	17.6	4.9	159.7	29.5
1947	10.9	5.6	165.0	29.5
1948	13.8	6.0	172.9	28.8
1949	12.6	6.2	179.4	28.9
1950	12.0	6.9	184.6	26.8
1951	16.0	7.9	192.8	24.4
1952	14.3	8.6	198.6	23.1
1953	20.3	9.2	210.3	22.9
1954	9.5	9.4	210.6	22.4
1955	21.9	10.1	222.5	22.0
1956	24.7	10.8	236.5	21.9
1957	20.0	11.4	245.2	21.5
1958	18.9	11.4	252.8	22.2
1959	20.6	12.4	261.2	21.1
1960	13.9	13.0	262.3	20.2
1961	17.2	13.4	266.3	19.9
1962	19.5	13.6	272.3	20.0
1963	18.2	14.5	276.2	19.0
1964	20.3	15.3	281.3	18.4
1965	21.3	16.2	286.5	17.7
1966	20.2	17.5	289.3	16.5
1967	21.8	18.4	292.9	15.9
1968	13.7	19.4	287.3	14.8
1969	8.4	20.7	275.1	13.3
1970	37.2	22.0	(261.6)[1] 290.7	13.2
1971	9.8	22.1	278.8	12.6
1972	9.6	22.5	266.1	11.8

Source: Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1972, AGA, API, and CPA, Vol. 27, May, 1973. 1/ National Gas Reserves Study, FPC., May, 1973.

TABLE 11

CRUDE OIL: PROVED RESERVES AND PRODUCTION
(Billions of Barrels)

Year	Reserve Addition	Net Production	Proves Reserves Year End	R/P Ratio
1946	2.7	1.7	20.9	12.3
1947	2.5	1.9	21.5	11.3
1948	3.8	2.0	23.3	11.7
1949	3.2	1.8	24.6	13.7
1950	2.6	1.9	25.3	13.3
1951	4.4	2.2	27.5	12.5
1952	2.7	2.3	28.0	12.2
1953	3.3	2.3	28.9	12.6
1954	2.9	2.3	29.6	12.9
1955	2.9	2.4	30.0	12.5
1956	3.0	2.6	30.4	11.7
1957	2.4	2.6	30.3	11.7
1958	2.6	2.4	30.5	12.7
1959	3.7	2.5	31.7	12.7
1960	2.4	2.5	31.6	12.6
1961	2.7	2.5	31.8	12.7
1962	2.2	2.6	31.4	12.1
1963	2.2	2.6	31.0	11.9
1964	2.7	2.6	31.0	11.9
1965	3.0	2.7	31.4	11.6
1966	3.0	2.9	31.4	10.8
1967	3.0	3.0	31.4	10.5
1968	2.5	3.1	30.7	9.9
1969	2.1	3.2	29.6	9.3
1970	12.9	3.3	39.0	11.8
1971	2.3	3.3	38.1	11.5
1972	1.6	3.3	36.3	11.0

Source: Reserves (Vol. 27). op. cit. p. 24.

5. **Reserve/Production Ratio** -- relates annual production to current estimates of proved reserves. The ratio indicates how many years current proved reserves can meet current annual production levels. The 1972 U.S. ratio is 11.0.

The ten regions were ranked from most favorable to least favorable for each of these indicators. The rankings are shown in Appendix 2, Tables 1 through 5. The Atlantic Coast is shown in only two rankings and offshore Florida, Alabama, and Mississippi is shown in one ranking. No proved reserves lie in either region. Estimates of discoverable oil are not available for offshore Florida, Alabama and Mississippi from the NPC estimate. Table 12 on the following page shows the highest ranked regions for each descriptor.

The Gulf of Mexico does not rank among the three most attractive regions for either proved oil reserves or remaining discoverable oil in place. The Gulf ranks fifth and sixth on these measures. The low ranking on the basis of proved reserves is not an important indicator of where future exploration can be expected, because it measures only oil which is producable under current operating and economic conditions. If discoverable reserves are available, the low ranking suggests that exploration must be expanded to maintain production levels. The Gulf ranks fifth with a Reserve/Production ratio of 6.4, indicating that proved reserves will be adequate to meet current production levels for only another six and one-half years. In the near term, exploration in the Gulf probably can be expected to intensify, because producers are experienced in that area, past exploratory drilling success rates are high, and transportation and storage facilities are nearby.

In the long term, areas with larger discoverable reserves but insignificant current production levels may attain greater importance. Major drawbacks will restrict exploration in the near to mid-term:

- Alaska ranks first, but high exploration and production costs and lack of transportation facilities are major disadvantages.'

- The highest ranking offshore area is the Pacific Coast, ranked third, but offshore California -- the only part of the Pacific Coast in which exploratory drilling has been initiated -- generally will require deeper drilling than the Gulf. Additionally, environmental problems must be solved before extensive exploratory can be resumed. Eventually, however, the Pacific Coast -- especially offshore California -- promises to be an important producing region.

- Exploratory interest currently is focused on the Atlantic Coast, but no leases have been proposed to date. The environmental review procedures plus lengthy start up operations will preclude significant production before 1985.

TABLE 12

SUMMARY OF OIL RESERVES DISTRIBUTION: THREE MOST ATTRACTIVE REGIONS AND THE GULF OF MEXICO

Rank by Indicator	Region	Value
1. Proved Reserves:		
Ranked 1st	Southwest	12 bb
Ranked 2nd	Alaska	10 bb
Ranked 3rd	West	5 bb
Ranked 5th	Gulf of Mexico	3 bb
2. Ultimate Recovery as % of Original: Oil-in-Place		
Ranked 1st	S. Louisiana and S. Texas	47%
Ranked 2nd	Gulf of Mexico	46%
Ranked 3rd	Alaska	39%
3. Remaining Discoverable Oil-in-Place:		
Ranked 1st	Alaska	119 bb
Ranked 2nd	West	88 bb
Ranked 3rd	Pacific Coast	48 bb
Ranked 6th	Gulf of Mexico	27 bb
4. Cumulative Production as a % of Ultimate Recovery:		
Ranked 1st	Alaska	5%
Ranked 2nd	Gulf of Mexico	50%
Ranked 3rd	Southeast	75%
5. Reserve/Production Ratio:		
Ranked 1st	Alaska	144.3
Ranked 2nd	Southwest	9.8
Ranked 3rd	East	7.6
Ranked 5th	Gulf of Mexico	6.4

Three lower 48 onshore regions have higher discoverable reserves than the Gulf of Mexico -- the West, the Southwest, and South Louisiana and South Texas. Exploration is likely to remain at high levels in each. The West has highest discoverable reserve estimates for the lower 48 onshore and appears to be the most promising lower 48 onshore region. The Gulf's high value for ultimate recovery as a percent of original oil-in-place suggests that much of the oil in known reservoirs can be produced and the depletion rate of only 50 percent shows that half of proved reserves remain to be produced. Alaska has the lowest depletion rate at 5 percent and all other regions have rates of 75 percent or greater.

Regional Distribution of Natural Gas Reserves

A similar analysis was conducted to determine the relative attractiveness of the ten regions based on their reserves of natural gas. Seven descriptors were selected for analysis. Additional measures are available for natural gas because estimates of potential supply published by the Potential Gas Committee are broken out by depth of reservoirs and probability of discovery -- both important indicators of the likelihood of exploratory drilling. The seven characteristics are:

1. Proved reserves.

2. Future Potential supply -- measures discoverable reserves. High estimates suggest the region is attractive for all types of exploratory drilling.

3. Future potential supply, probably only -- measures natural gas in existing fields which has not been proved. Probable supply has the highest likelihood of discovery. High estimates suggest the region is attractive, especially for near term exploratory drilling in existing fields.

4. Future potential supply, less than 200 meters deep offshore and 15,000 feet deep onshore only -- measures potential supply which presumably can be recovered without very deep, expensive drilling.

5. Ultimate recovery as a percent of ultimate discovery -- measures the extent to which the total discoverable natural gas already has been proved and produced. A low percent suggests the region's natural gas is not yet depleted.

6. Cumulative production as a percent of ultimate recovery -- measures the extent to which proved reservoirs have been depleted by production.

7. Reserve/production ratio -- indicates how many years proved reserves can meet current annual production levels. The 1972 U.S. ratio is 11.8.

The ranking from most to least favorable are shown in Tables 6 through 12 in Appendix 2. Table 13 presents a summary of results for the three highest regions for each indicator and for the Gulf of Mexico.

The Gulf of Mexico ranks among the three most favorable regions for all the indicators we selected. It stands out as an area highly attractive for future exploration of natural gas. Only Alaska, where exploration is likely to be limited in the near term for reasons discussed previously, and the Southwest have larger estimated potential supply. Looking at only the potential supply of natural gas classified probable (relating to the expansion of existing fields) the Gulf of Mexico and South Louisiana and South Texas share the highest ranking with 57 trillion cubic feet each. This suggests that exploratory drilling within existing fields will intensify. The Gulf of Mexico ranks third in potential supply at shallow depths -- less than 200 meters deep offshore and 15,000 feet onshore. This is a very favorable indicator for the likelihood of future exploratory drilling because drilling-costs increase with depth and, at current prices, many deep reservoirs are non-commercial.

Thirty-eight percent of total proved reserves in the Gulf have been produced. Only Alaska, at 3 percent, has a lower value of cumulative production as a percent of ultimate recovery. The Gulf ranks third in proved reserves, suggesting that production levels in the Gulf will remain high. Finally, ultimate recovery as a percent of ultimate discovery is only 30 percent for the Gulf. That is, 70 percent of ultimately discoverable resources remain to be discovered. Alaska and the Pacific Coast are ranked first with 8 percent each. The only lower 48 onshore region with a lower percent is the Southeast at 20 percent.

The Gulf of Mexico ranks second for the Reserve/Production ratio, following only Alaska, indicating that reserves in the Gulf are adequate to meet current production levels longer than any other lower 48 region.

Regional Variation in Exploration and Development Conditions

An important determination of any region's attractiveness for future exploration lies in the estimated costs of discovering potential supplies. Onshore, much of the "easy-to-find oil" at shallow depths has been discovered. The simple exploratory process used--location of drillable structures by reflection seismographic surveys -- will be increasingly ineffective onshore because a significant proportion of estimated undiscovered oil and gas is in stratigraphic traps and other complex structural situations. However, simple structure hunting can be expected to be effective offshore for some time to come. Stratigraphically controlled fields are significantly more expensive to develop because many more exploratory and developmental and dry holes generally are required to determine the dimensions of the reservoir.

In order to assess which regions are most attractive with regard to favorable exploration and development conditions, we identified thirteen indicators, each of which measures one aspect of the cost of exploration:

TABLE 13

SUMMARY OF NATURAL GAS RESERVES DISTRIBUTION: THREE MOST ATTRACTIVE REGIONS AND THE GULF OF MEXICO

Rank by Indicator	Region	Value
1. Proved Reserves (trillion cubic feet):		
Ranked 1st	South Louisiana and South Texas	89
Ranked 2nd	Southwest	75
Ranked 3rd	Gulf of Mexico	39
2. Potential Supply (trillion cubic feet):		
Ranked 1st	Alaska	366
Ranked 2nd	Southwest	235
Ranked 3rd	Gulf of Mexico	148
3. Probable Potential Supply (trillion cubic feet):		
Ranked 1st	Gulf of Mexico and S. Louisiana & S. Texas	57
Ranked 2nd	Alaska	54
Ranked 3rd	Southwest	46
4. Potential Supply -- less than 200 meters deep offshore and 15,000 feet deep onshore (t.c.f.):		
Ranked 1st	Southwest	161
Ranked 2nd	Alaska	148
Ranked 3rd	Gulf of Mexico	133
5. Ultimate Recovery as % of Ultimate Discovery:		
Ranked 1st	Alaska and Pacific Coast	8%
Ranked 2nd	Southeast	20%
Ranked 3rd	Gulf of Mexico	30%
6. Cumulative Production as Percent of Ultimate Recovery:		
Ranked 1st	Alaska	3%
Ranked 2nd	Gulf of Mexico	38%
Ranked 3rd	South Louisiana and South Texas	60%
7. Reserve/Production Ratio:		
Ranked 1st	Alaska	214.4
Ranked 2nd	Gulf of Mexico	21.0
Ranked 3rd	East	17.2

1. Average cost per foot of total oil wells drilled, 1971 -- Measures the average cost of drilling all successful exploratory and developmental oil wells. (Costs by type of well or more recent cost data are not available.)
2. Average cost per foot of total gas wells drilled, 1971.
3. Average drilling cost per barrel of new proved oil reserves, 1971.
4. Average drilling cost per million cubic feet of new proved gas reserves, 1971.
5. Average depth of total oil wells drilled, 1972 -- Deep wells indicate high costs, not only because of the greater depth but because costs per foot tend to be higher at greater depths.
6. Average depth of total gas wells drilled, 1972.
7. Proved reserves added per foot of oil wells drilled, 1972 -- Measures the "productivity" of the reservoir.
8. Proved reserves added per foot of gas wells drilled, 1972.
9. Average depth of exploratory oil wells drilled, 1971.
10. Average depth of exploratory gas wells drilled, 1971.
11. Percent of successful total exploratory wells, 1971 -- A high percentage is a very favorable indicator, because a large component of total exploration costs is represented by dry hole costs.
12. Percent of successful new field wildcats, 1971 -- New field wildcats are wells drilled in fields not previously productive, so a high success rate is a favorable indicator of the likelihood of discovering new reservoirs.
13. Percent of successful new pool wildcats, 1971 -- New pool wildcats are wells drilled in productive fields outside the limits of proven pools.

The regional rankings from most to least favorable are shown in Tables 13 through 25 in Appendix 2. No drilling has occurred in the Atlantic Coast or offshore Florida, Mississippi or Alabama, so they are not included in any rankings. A limited amount of exploratory drilling has occurred in the Pacific Coast, primarily offshore California, but published data are unavailable for some of the descriptors we selected. A summary showing the three most attractive regions and the Gulf of Mexico is shown in Table 14 on the following page.

TABLE 14

SUMMARY OF EXPLORATION AND DEVELOPMENT CONDITIONS: THREE MOST ATTRACTIVE REGIONS AND THE GULF OF MEXICO

Rank by Indicator	Region	Value
1. Average Cost Per Foot of Oil Wells Drilled, 1971		
Ranked 1st	East	$11.33
Ranked 2nd	West	11.68
Ranked 3rd	Southwest	12.97
Ranked 6th	Gulf of Mexico	55.59
2. Average Cost Per Foot of Gas Wells Drilled, 1971		
Ranked 1st	East	$14.28
Ranked 2nd	West	16.59
Ranked 3rd	Southwest	27.38
Ranked 5th	Gulf of Mexico	69.56
3. Average Depth of Total Successful Oil Wells Drilled, 1972		
Ranked 1st	East	2435 ft.
Ranked 2nd	Southwest	4237
Ranked 3rd	West	4587
Ranked 6th	Gulf of Mexico	10591
4. Average Depth of Total Successful Gas Wells Drilled, 1972		
Ranked 1st	East	3740
Ranked 2nd	Southwest	5114
Ranked 3rd	West	5496
Ranked 8th	Gulf of Mexico	10904
5. Average Drilling Cost Per Barrel of New Proved Oil Reserves, 1971		
Ranked 1st	Southwest	$.23
Ranked 2nd	Southeast	.46
Ranked 3rd	South Louisiana and South Texas	.49
Ranked 6th	Gulf of Mexico	.69
6. Average Drilling Cost Per Million Cubic Feet of New Proved Gas Reserves, 1971		
Ranked 1st	Alaska	$.005
Ranked 2nd	East	.015
Ranked 3rd	West	.035
Ranked 5th	Gulf of Mexico	.063
7. New Proved Reserves Per Foot of Oil Wells Drilled, 1972		
Ranked 1st	Gulf of Mexico	64 barrels
Ranked 2nd	West	49
Ranked 3rd	Alaska	48
8. New Proved Reserves Per Foot of Gas Wells Drilled, 1972		
Ranked 1st	Gulf of Mexico	11.5 m.c.f.
Ranked 2nd	Alaska	10.3
Ranked 3rd	Southwest	4.1
9. Average Depth of Exploratory Oil Wells Drilled, 1971		
Ranked 1st	East	2535
Ranked 2nd	Southwest	5216
Ranked 3rd	West	2926
Ranked 5th	Gulf of Mexico	12278
10. Average Depth of Exploratory Gas Wells Drilled, 1971		
Ranked 1st	East	3178
Ranked 2nd	West	5593
Ranked 3rd	Southwest	7878
Ranked 7th	Gulf of Mexico	12464
11. Percent of Successful Exploratory Wells, 1971		
Ranked 1st	Alaska and East	20%
Ranked 2nd	Southwest	19
Ranked 3rd	South Louisiana and South Texas	17
Ranked 4th	Gulf of Mexico	15
12. Percent of Successful New Field Wildcats, 1971		
Ranked 1st	Gulf of Mexico	13%
Ranked 2nd	Southeast	12
Ranked 3rd	South Louisiana and South Texas	11
13. Percent of Successful New Pool Wildcats, 1971		
Ranked 1st	South Louisiana and South Texas	35%
Ranked 2nd	East	26
Ranked 3rd	West	17
Ranked 5th	Gulf of Mexico	9

The results of our analysis of exploration costs shows that drilling costs almost without exception are substantially higher for offshore regions and Alaska than for the lower 48 onshore regions. Offshore exploration costs are much higher than onshore costs because of additional equipment and operations required. In shallow water, costs are about double those of land operations since paths must be dredged for drilling barges and flow-lines and special foundations are needed to elevate wells and production facilities above water. In 100-300 feet of water, the cost of drilling wells from individual locations frequently is prohibitive. Groups of 3-18 exploratory wells are drilled directionally from one fixed support structure or platform. Offshore costs using fixed platforms in water 100-300 feet deep are three to four times those onshore. Platforms become more expensive as water depth increases. In water depths nearly 600 feet deep, operating costs are about 6 times onshore costs. Beyond 600 feet of water, the cost of fixed platforms is prohibitive, so drilling will probably be done from floating vessels (except in unique situations such as the Santa Barbara Channel where the oil fields are located in deep water close to shore).

Costs also increase greatly in offshore areas with severe weather conditions -- frequency of high waves, severe storms, high sea swell (length of waves) and ice infested waters. The Santa Barbara Channel has the calmest wave conditions of major offshore areas, the Gulf of Mexico also is relatively calm, and the Gulf of Alaska has the most severe wave conditions.

The cost per foot of total successful oil wells drilled in 1971 was $56 for the Gulf, $60 for the Pacific Coast and $117 for Alaska. This compares to a range of $11 to $23 for the lower 48 onshore regions. For gas wells, the cost per foot was $70 for the Gulf and $132 for Alaska. (No successful gas wells were drilled in the Pacific Coast.) One lower 48 onshore region -- the Southeast -- had higher costs per foot than the Gulf for gas wells. The drilling costs per foot in the other lower 48 regions ranged from $14 to $29.

Offshore wells also generally are deeper than onshore wells. The deepest exploratory wells which found gas in 1971 were in the Gulf of Mexico with an average depth of 12,464 feet. However, gas wells drilled in the Southeast almost matched this depth; the average well there was 12,385 feet deep. Exploratory oil wells also were deepest in the Gulf of Mexico in 1971.

While all measures of average cost per foot and average depth per well indicate that the offshore areas and Alaska are unattractive relative to most onshore areas, especially the East and West, measures of productivity lead to the opposite conclusion. The Gulf of Mexico ranks first in both proved oil reserves and natural gas reserves added per foot of drilling. In 1972, 64 barrels of oil were added to proved reserves per foot of drilling in the Gulf. The lowest reserve addition was for the East, where only 3 barrels per foot were added. Similarly, the Gulf ranked first by a wide margin over lower 48 onshore regions in the addition of proved gas reserves per foot of drilling. 11.5 million cubic feet were added per foot of drilling in the Gulf, whereas the range for lower 48 onshore regions was 4.1 to 2.1 million cubic feet.

The higher productivity of oil reservoirs in the Gulf of Mexico is more than offset by higher drilling costs so that the Gulf has the highest drilling costs per barrel of the lower 48 regions. Drilling costs per barrel in the Gulf of Mexico are $.69 compared to a range of $.23 to $.61 in other lower 48 regions. Only Alaska, at $.78, has higher drilling costs per barrel. For natural gas reservoirs, the higher productivity in the Gulf compensates to some degree for higher drilling costs. The drilling cost per million cubic feet of new proved reserve is $.063 in the Gulf. South Louisiana and South Texas have higher costs at $.075. The range for other lower 48 regions is $.015 to $.063. The cost for Alaska in 1971 was exceptionally low, $.005 per barrel, because one successful gas well resulted in a large upward reappraisal of proved reserves.

The cost of dry holes needed to determine the dimensions of a reservoir is a large component of total exploration costs. Thus the percentage of successful wells is an important indicator of costs. The Gulf ranked 4th in the percentage of total successful exploratory wells in 1971. Alaska and the East both are ranked first with a 20 percent success rate. The Gulf's success rate is 15 percent and the Pacific Coast's success rate (the lowest) is 5 percent. The Gulf ranks first in the success rate of new field wildcats at 13 percent in 1971 and fifth in the success rate of new pool wildcats at 9 percent. Overall, the success rate of exploratory wells in the Gulf appears better than the Southeast, the West, and the Pacific Coast, and not as good as the East, Southwest, and South Louisiana and South Texas. However, the East is not a major producing area, so only two major regions appear more favorable on this basis than the Gulf and their advantage is not great.

III

THE EFFECTS OF GOVERNMENT POLICIES, ECONOMIC CONDITIONS, AND COST FACTORS ON THE EXPLORATION DECISION

Federal Policies

Oil and natural gas producers are subject to numerous Federal policies which impact on the location, volume, and cost of exploratory operations. These policies are based on the authority of several agencies, principally the Federal Power Commission, the Internal Revenue Service, the Department of Interior, the Environmental Protection Agency, and the new Federal Energy Office. The major categories of regulations are:

- tax regulations which apply to all U.S. corporations;
- tax regulations which apply only to mineral producers;
- leasing regulations for public lands, and the Outer Continental Shelf (OCS);
- the Economic Stabilization Program;
- FPC regulation of utilities;
- import policy; and
- environmental regulations.

Each of these is discussed briefly in this section. Our purpose is to provide sufficient background necessary to understand the sensitivity analyses we conduct using the offshore exploration model, not to provide a comprehensive discussion of each topic. Not every regulation discussed is incorporated in the model; the sensitivity of the offshore exploration decision to changes in these is also discussed briefly.

Corporate Taxes

Oil and natural gas producers are subject to the corporate income tax, currently 50 per cent (or taxes which apply if the operation is not incorporated). Producers also can elect among several allowable depreciation methods (e.g., straight line, 50 per cent declining balance, unit of production, etc.) to depreciate buildings and equipment. Because these taxes apply to all corporations, they obviously cannot be used as policy levers to influence the exploration decisions of oil and natural gas producers.

Taxes Applying to Mineral Producers

Producers may elect to deduct some drilling and development costs as expenses in the taxable year, rather than capitalize and depreciate them over a longer period. This provision can reduce taxable income substantially and act to increase cash flow. Such expenses are termed intangible drilling and development costs. The Secretary of the Interior is empowered by the Internal Revenue Code to specify which expenditures are intangible drilling and development costs and may be expensed. Some examples are labor, materials, and overhead costs incurred in developmental drilling operations. Generally, any materials having salvage value must be capitalized. Additionally, the costs of geological and geophysical exploration which are incurred to acquire or develop leases must also be capitalized. It is in the operator's interest to identify and expense the maximum amount of intangible drilling and development costs.

The exploratory drilling costs of dry holes, e.g., unsuccessful wells, are treated differently than similar costs for successful wells. All dry hole costs may be expensed, compared to only intangible drilling and development costs for successful wells. This provision is a method to mitigate the expenses accruing to operators from unsuccessful exploratory drilling.

The depletion allowance is a method to compensate producers from the exhaustion of mineral resources resulting from production. Currently the percentage depletion allowance is 22 per cent. It is applied to total revenues from crude production and is subtracted from gross pretax income. The allowance may equal up to 50 per cent of the firm's net pretax income. The percentage depletion allowance permits operators to recover more costs than spent to acquire and develop the property because it is applied to revenues and may be used for the producing life of the reservoir.

An alternative depletion method, designated cost depletion, may be used by producers. Cost depletion is computed by dividing the cost of the mineral interest by estimated recoverable reserves (proved and probable) and multiplying this amount by the number of units sold during the taxable year. The cost depletion method is rarely utilized, since it is approximately equivalent to a 4 per cent rate of percentage depletion.

Oil and gas companies are permitted to treat royalties paid to foreign governments for drilling rights as an income tax which may be offset "dollar for dollar" against their U.S. corporate income tax liability.

Obviously, after tax profit expectations will increase, the higher the percentage depletion allowance and the more intangible drilling and development costs which may be expensed. Taxes could be modified to reduce or eliminate the advantageous provisions which apply to mineral producers. The resulting higher costs generally would be passed on to consumers, and some reservoirs which are only marginally profitable at present probably would be withdrawn from production. Conversely, the tax benefits enjoyed by the hydrocarbon industry could be increased. Continuing pressures for tax reform weigh against this alternative.

Federal Public Land and OCS Leasing Policies

Mineral exploration and production on Federal lands are subject to regulations which insure that an interest in production and full title to the land is retained by the United States. Prior to 1920, the right to explore for and produce oil and natural gas from the public domain was subject to the placer mining laws. Those who made a proper placer location were permitted to explore the property for oil and gas and, on proof of valuable discovery, could secure a patent from the United States to all land covered by the claim. The patent conveyed full title to the land. The Mineral Leasing Act of 1920, as amended, established procedures for leasing Federal lands and securing royalties for the United States based on the volume of mineral production.

Federal lands are classified by the United States Geological Survey as wildcat or proven. Proven lands are within the known geological structures of existing oil fields whereas wildcat lands are not known to contain hydrocarbons. Wildcat lands may be leased by payment of a small annual rental fee; proven lands are leased by competitive bidding for a bonus and royalty payments ranging from 12-1/2 to 25 percent, depending on the volume of production, are levied.

Provisions of the Mineral Leasing Act do not extend to the Outer Continental Shelf (OCS). OCS lands are leased under authority of the Outer Continental Shelf Lands Act of 1953. This Act extends the civil and political jurisdiction of the United States to the OCS and grants the Secretary of the Interior authority to lease land for mineral exploration and development. Leasing must be by competitive bidding. (There is no distinction between wildcat and proven lands for the OCS.) The Secretary may elect to require competitive cash bonuses and fixed royalties of no less than 12-1/2 per cent or competitive royalties no less than 12-1/2 per cent and a fixed bonus. All OCS lease sales to date have required competitive cash bonuses and the royalty rate is one-sixth or .167. Tracts are leased in blocks of 5,000 acres.

The boundaries of the OCS remain indefinite. The statutory definition of the OCS is "all submerged lands lying seaward and outside of the area of lands beneath navigable waters (as defined in the Submerged Land Act) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control." The Submerged Lands Act grants several coastal states ownership of all lands under navigable waters up to three geographic miles from the coastline or seaward boundaries which existed at the time of the state's entry into the Union. In several states, including Louisiana and 12 East Coast states, the landward OCS boundary remains in dispute. The Federal government brought a lawsuit against the 12 East Coast states (U.S. v. Maine et.al.) in 1969 before the Supreme Court to settle the jurisdictional dispute. The Supreme Court probably will not make a decision until the summer of 1975, and the U.S. has agreed not to initiate leasing procedures in the Atlantic without the permission of the states involved in the suit until the Court has ruled.

The seaward boundaries of the OCS also are subject to different interpretations. The common geological interpretation is that the Outer Continental Shelf ends where the Continental Slope begins. However, at least one Interior Department statement has held that the Outer Continental Shelf Land Act is applicable as far seaward as mineral production is technically feasible.

Every recent OCS lease sale has generated record bonus payments. From 1953 to 1970, lease sales generated bonuses totalling $4.3 billion for 7.1 million acres. The average bonus paid per acre was $929 during the period 1966-71 compared to $278 during 1954-59. The 1973 sale in offshore Florida, Alabama, and Mississippi realized bonus payments of about $53,000 per acre in one tract. The earliest offerings were relatively large and thus did not permit thorough tract evaluation. Producers also lacked experience offshore. Consequently, bids were relatively cautious. High drilling success rates and expectations of discovering large recoverable reserves have driven bids up. For example, of 48 domestic oilfields in 1971 with recoverable reserves in excess of 100 bbl, 17 were offshore.

The President promised to triple the rate of OCS leasing in his April, 1973 Energy Message from one to three million acres per year. Before this policy was implemented, however, the President announced plans in January, 1974 to lease 10 million OCS acres, beginning in 1975. The 10 million acre target is more than the total offshore acreage leased during the 20 year OCS leasing program. The Interior Department proposes to lease acreage in the Atlantic OCS and Gulf of Alaska, in addition to the Gulf of Mexico and offshore California. All sales are contingent upon completion of necessary environmental, technical, and economic studies.

The mechanism of a combined bonus and royalty lease payment is a method of sharing the risk of offshore exploration between the government and the operator. This is a characteristic of both the fixed royalty/variable bonus system currently used and a fixed bonus/variable royalty system.* If the latter were adopted, the level of the fixed bonus plus the policy and economic scenario perceived by bidders would determine the decision to bid and the level of the royalty bids.

Increasing the royalty payment is a potential way to increase the operator's costs and thereby reduce the rate of offshore exploration. Using a fixed bonus/variable royalty system and setting high fixed bonus payments also would increase operator costs. Our analysis suggests, however, that offshore prospects are so attractive that increases in operating costs which might result from changes in tax and leasing regulations are not likely to alter the decision to bid for offshore leasing rights. Instead, the amount of the bonus payments would be reduced.

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* If a fixed or variable bonus only were used, the operator would incur all the risks, thus increasing his costs. Conversely, the government would incur all the risk with use of a fixed or variable royalty only.

Economic Stabilization Program

Crude and retail oil prices remain controlled under Phase IV. Ceiling prices are in effect for retailers and crude prices are based on a two-tiered system; existing levels of crude production are subject to ceiling prices and new crude is priced by the market. When Phase IV began, most U.S. crude was selling in the \$4.20 to \$4.30/bbl range. The ceiling for old oil currently is \$5.25 per barrel and new oil is selling upwards of \$7.00 per barrel, provided that old oil is also included in the sales "package" (generally at a one:one ratio). Increasing ultimate recovery from existing wells is the fastest way to profit from the two-tiered system. High prices for new crude are providing strong incentives for adoption of secondary recovery techniques in oil fields which previously were not economic. Incentives for increased onshore exploration -- in unexplored areas and in deeper horizons in known reservoirs -- also are strengthened. An increase in offshore exploration is not anticipated; large producers which operate offshore already have budgeted adequate funds from projected income at previous prices to lease and develop available offshore tracts.

Amendments to the Economic Stabilization Program also grant the President authority to allocate crude oil and oil products. Three petroleum allocation programs currently are in effect: (1) the Voluntary Petroleum Allocation Program established May 10, 1973; (2) the Mandatory Propane Allocation Program established October 2, 1973; and (3) the Mandatory Middle Distillates Allocation Program, effective as of November 1, 1973. An emergency oil allocation bill was passed by the House of Representatives in October. If this bill is enacted, it will require revisions of current allocation programs. This bill includes allocation procedures for gasoline, residual fuel oil, and crude oil. The allocation programs do not impact on the offshore/onshore exploration decision.

Federal Power Commission

The Federal Power Commission regulates the price of natural gas in interstate commerce. (Natural gas and other regulated utilities are exempt from Economic Stabilization Program controls.) The industry and other critics have charged that low regulatory prices have resulted in low levels of exploration and inadequate supplies in the past.

The Administration favors deregulation of natural gas prices. Currently, natural gas prices are, in effect, decontrolled, as a result of the FPC's policy, effective September 14, 1973, which permits interstate pipelines to make emergency purchases of natural gas at any price for 180 days. This policy is being challenged in the courts in numerous jurisdictions. The Administration's proposed Gas Supply Act of 1973 would deregulate wellhead prices of new natural gas (from wells discovered after April 15, 1973). A single national ceiling is expected for gas from old wells. A bill sponsored by Senator Stevenson (Dem., Illinois) would exempt small producers from controls but extend regulation of the 30 largest producers (representing about 85 per cent of natural gas sales) to include intrastate sales. Increased revenues resulting from higher prices due to decontrol (or higher price ceilings) might provide incentives for increased exploration - particularly offshore where discovery of large reserves is anticipated - but also could provide substantial windfall profits to producers.

Import Policy

Official U.S. fuel import policy was embodied in the Mandatory Oil Import Program from 1959 through early 1973. This program attempted to limit foreign oil to a small and fixed proportion of domestic production. Historically, the cost of domestic crude oil was higher than the cost of imported crude, so import quotas provided leverage to stabilize domestic prices. Recent fuel shortages, a high dependency on imported fuels, at least through 1980 or 1985, and rapidly rising price increases for imported crude combined to make import quotas unworkable.

Effective May 1, 1973, the quota system was replaced with a new import program, which establishes a volume for each type of fuel which can be imported duty-free and fees for additional imports which are allowed without volume restrictions. The daily volume of crude imports increased 32 per cent over 1972 by the end of the summer - from 4.5 Mb/d to 6.0 Mb/d. Most of the increase was from the Middle East, where crude imports rose from .4 Mb/d in 1972 to 1.3 Mb/d by September, 1973. The price of Middle Eastern crude increased steadily prior to the oil embargo and is rising even more sharply since the embargo was lifted.

New domestic energy supplies -- onshore oil and natural gas, clean fuels from coal or oil shale, or nuclear power - - generally remain costly relative to crude imports. But experience suggests that oil and natural gas from the OCS and Alaska could be developed and delivered to U.S. markets at less than the landed price of imported crude. Thus, offshore and Alaskan exploration can be expected to proceed as rapidly as leasing and other policies permit, even in the absence of import tariffs or quotas.

Imports of natural gas liquids will generally remain more expensive than domestic natural gas. The delivered cost of imported gas or gas manufactured from imported feedstock is about \$6.00 to \$9.00/bbl (equivalent basis). Additional domestic natural gas supplies probably can be developed at lower costs than imports for at least a decade.

Environmental Regulations

Environmental regulations significantly impact on the exploration decision directly, by restricting sites available for exploration and indirectly, by their effects on costs and relative prices. Public onshore and OCS lands can only be leased to oil and gas producers if studies determine that development can proceed in an environmentally satisfactory manner. All proposed lease sales are subject to review in Environmental Impact Statements and public hearings as required by the National Environmental Policy Act. Lease sales in the Atlantic OCS and the Gulf of Alaska have been postponed, pending the results of a special study by the Council on Environmental Quality to determine whether exploration and production can proceed with adequate protection of the environment. On the basis of its year-long study, the CEQ has concluded that leasing in both these areas can be safely undertaken, providing that carefully stipulated operating procedures are required.

The Outer Continental Shelf Lands Act grants authority to the Interior Department to issue operating orders for all oil and gas operations on Federally leased OCS lands. Their principal emphasis is on the safety of operations and the prevention of oil spills. The Federal Water Pollution Control Act authorizes the Environmental Protection Agency to require offshore oil and gas operators to develop contingency plans to minimize damage from spills of oil or other hazardous substances. Other legislation prohibits the discharge of oil in harmful quantities into the navigable waters of the U.S. or the discharge of refuse.

The primary authority for safeguarding the environment of the coastal zone -- generally the area between the three-mile seaward boundary of the state and Federal waters and an established number of yards inland - rests with the states. States also retain the primary authority over onshore oil and gas operations.

Other Federal legislation impacts on oil and gas exploration indirectly. The Clean Air Act affects the oil and gas industry in several ways. Its provisions increase the demand for low sulfur fuels, especially "sweet crude" and natural gas, in place of coal and residual fuel oil. An increase in the demand for low sulfur fuels and resulting relative price changes have positive effects on the incentives to increase the levels of offshore and onshore exploration and secondary recovery operations of oil and gas producers. In order to reduce the short-term demand for low sulfur fuels, the Administration has suggested that states avoid attempting to achieve secondary clean-air standards on the time schedule provided for primary standards.

Regulation of emission standards for petroleum refineries and storage vessels has no direct impact on the volume or distribution of exploratory activity. Regulations designed to insure adequate environmental [illegible] for exploratory and developmental drilling do not appear to impact on the offshore/onshore exploration decision. Higher operating costs are reflected in higher prices and, for offshore regions, lower bonus payments for the drilling rights.

State Policies

Two major categories of state policies impact on the volume and distribution of oil and gas exploration - conservation regulation and leasing of state onshore and offshore properties. Each is briefly discussed below.

Conservation Regulations

All oil and natural gas producing states have petroleum conservation statutes. The Federal government supports the states' regulatory efforts by sanctioning limited cooperation of the producing states under the Interstate Compact to Conserve Oil and Gas, publishing monthly hydrocarbon demand forecasts for each state, and subjecting operations on Federal lands to the production restrictions of the states in which these lands lie. For OCS lands, the conservation regulations of contiguous states apply.

Generally, conservation regulations attempt to cope with four problem areas:

- External damages to the environment - damage to subsurface fresh water and surface soil and streams by brine or uncaptured petroleum.
- Internal wastes - loss of ultimate recovery due to dense drilling and haste to get oil to the surface resulting from the "rule of capture." (Petroleum tends to migrate within the reservoir and the law holds that it belongs to anyone who captures it with wells on his property, regardless of its original location.)
- Instability of production and prices - under the "rule of capture" and in the absence of regulation, production would fluctuate widely causing unstable prices. One effect would be to discourage entry of new firms and thereby reduce exploration and production.
- Inequities among producers - various inequities resulting from the "rule of capture" are ameliorated. (For example, producers first connected to gathering lines could drain substantial amounts of petroleum from properties of neighbors awaiting connections in the absence of regulation.)

Prior to 1909, conservation regulations were concerned almost exclusively with preventing external damage to the environment and waste of natural gas. In response to enormous losses of oil and depressed prices from unregulated production of extensive new discoveries, Oklahoma enacted legislation from 1909 to 1915 designed to limit production, allocate production among wells in a reservoir, and outlaw discrimination by oil and gas purchasers and pipelines. Subsequently, similar regulations restraining production were enacted by all other producing states. The major features of current regulations are:

- Specification of well casing and plugging techniques and acceptable methods of disposing of brines;

- Specification of minimum distances between wells (or maximum production per acre per well by depth). This limits the rate of development costs;

- Specification of direct production restrictions which may be of two types: (1) Maximum Efficiency Rate of Production (MER) restrictions are applied to individual reservoirs and are intended to prevent rates of production that are high enough to reduce ultimate recovery of oil; (2) Market demand restrictions may be applied to individual reservoirs, areas within the state, or the entire state and are intended to limit production to expected demand for that area. Both tend to contribute toward price stability.

While their focus is not primarily on exploratory activities, conservation regulations do affect the volume and distribution of exploration. * All depth-acreage allowable schedules permit production increases as well depth increases, but production increases generally are more than proportionate to depth increases. This is in consideration of the fact that well drilling and operating costs increase more than proportionately to depth. Schedules for offshore areas of Louisiana and Texas also provide for greater absolute production allowances than onshore areas. Production allowances also increase as acreage per well is increased, in consideration of the fact that wider spacing increases the pay-out period. Increasing production allowance more than proportionate to depth increases and setting high allowances for offshore areas encourage the exploration of relatively high cost opportunities, especially offshore, at the expense of lower cost onshore opportunities. Different schedules from state to state affect the allocation of exploration between states.

Leasing of State Onshore and Offshore Lands

State onshore and offshore properties are leased to oil and natural gas producers. The Submerged Lands Act grants to the coastal states ownership of all

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* For a detailed discussion, see McDonald, Stephen L., Petroleum Conservation in the United States, An Economic Analysis, Resources for the Future, 1971.

lands under navigable waters to three geological miles from their coastlines or to the seaward boundaries which existed at the time they were admitted to the Union. The Act also grants ownership to all states of lands under inland waters.

Most leases in state waters are for offshore Louisiana. About 75 per cent of offshore Louisiana production is in state waters. California and Texas also have granted offshore leases. Offshore leasing by California was virtually halted after the well blowout in the Santa Barbara Channel in 1969. Public hearings have only recently been held on the resumption of operations in the channel.

Industry pressures to increase the amount of offshore acreage available for leasing, while focusing on OCS lease sales, also affect state lease sales. However, the volume of state acreage for new leasing obviously is limited relative to OCS acreage. Additionally, public opinion is more likely to approve of new operations beyond the visibility of the shoreline, which suggests that operations in the OCS would be preferable to those in state waters.

The Mathematical Model Used to Simulate the Offshore Exploration Decision

A mathematical model is used to test the sensitivity of the offshore exploration decision to Federal policies, economic conditions, and costs. The model computes the Expected Present Value of production revenues less costs for a typical offshore drilling tract. (Costs are net of lease bonuses but include royalties.) If the Expected Present Value is positive, a firm will be willing to pay a bonus equal to or less than the Expected Present Value to acquire the drilling rights. Sensitivity testing of the model determines the maximum bonus lease bid for a typical offshore tract under alternative values for policy, economic, and cost parameters.

We hypothesize that under a reasonable range of Federal policy alternatives (short of a restriction or cessation of offshore leasing), economic conditions, and costs, the Expected Present Value of the typical offshore site will always be positive. That is, government policies have no impact on the decision to explore domestic offshore versus onshore regions; instead, they affect only the size of the bonus payment. This is because the alternatives to expanding offshore production, which include expanding onshore production or developing synthetic fuels from oil shale and coal, are more costly. We test our hypothesis to four sensitivity analyses. These are described in the following section.

Exhibit 2 on the following page shown how the mathematical model is expressed and the definition of each variable. A detailed discussion of how the model is derived is shown in Appendix 6.

EXHIBIT 2

THE MATHEMATICAL MODEL USED TO SIMULATE THE OFFSHORE EXPLORATION DECISION

The model is expressed as:

$$EPV^{*} = Y\left\{\left[\frac{(1-c+cd)(1-r)}{A+I}\,P\cdot A\cdot R\right]-\left[\frac{(1-c)O\cdot A\cdot R}{A+I}\right]-\left[(1-xc)R\cdot B\cdot W\right]\right\}-(1-cf)(1-Y)H$$

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*Expected Present Value, net of all costs except the bonus payment.

Five variables describe tax and leasing policies:

c = the corporate tax rate,
d = the rate of percentage depletion,
r = the royalty rate,
f = the fraction of dry whole costs which can be expensed immediately, and
x = the fraction of exploratory and developmental drilling costs which can be expensed immediately.

Two variables describe economic conditions:

I = the cost of capital, and
P = the price per barrel of output (Gas is on an equivalent barrel basis.)

Seven variables describe characteristics of the potential drilling site:

Y = the probability of commercial production,
A = the decline rate,
O = operating costs per barrel of output,
B = wells drilled per barrel of recoverable reserves,
W = weighted average cost per well of exploratory and developmental wells,
H = dry hole costs per barrel, and
R = recoverable reserves (equal to cumulative production over the producing life of the tract).

The model shows that the Expected Present Value (EFV) will increase as:

- the corporate tax rate (c) decreases;
- the rate of percentage depletion (d) increases;
- the fraction of dry hole costs which can be expensed immediately (f) increases;
- the fraction of developmental drilling costs which can be expensed immediately (x) increases; and
- the royalty rate (r) decreases.

The magnitude of the effects of tax policies on the EPV of any tract will depend upon other characteristics of the tract. Thus, changing tax policies will result in both changes in the aggregate value of lease bids and the distribution of lease bids among tracts.

The Base Case: A Typical Operation in the Gulf of Mexico

The values of each variable for the base case - which we define as a typical operation in the Gulf of Mexico - are discussed in this section. Subsequently, policy, economic and cost parameters will be varied to test the sensitivity of the Expected Present Value to these changes. Our values for variables in the base case are, in part, derived from work by L. K. Weaver, et. al.* who analyzed the rate of return for operations on a typical 5,000 acre tract in the Gulf of Mexico.

The Cost of Capital (I)

The cost of capital is represented by the after-tax real rate of return on total assets (as distinguished from the nominal rate of return which is not adjusted for inflation). Changes in the cost of capital may impact differently on the attractiveness of onshore versus offshore development because offshore development is both more capital intensive and the capital expenditures typically are required earlier in the development process. In order for offshore development to be more attractive on the margin than onshore development, other characteristics of offshore regions must be more attractive. As our previous analysis indicated, this is true for the Gulf of Mexico and probably can be assumed for other offshore regions. Oil and natural gas reserves found per foot of drilling in the Gulf are substantially higher than in any onshore region.

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* Weaver, L. K., et al. Composition of the Offshore U.S. Petroleum Industry and Estimated Costs of Producing Petroleum in the Gulf of Mexico, Department of the Interior, Bureau of Mines, Circular 8557, 1972.

The after tax rate of return earned by all manufacturing firms is about 8.0 per cent. For petroleum companies listed in Fortune's top 500 it is 9.4 per cent. The average rate of return for seven successful Gulf oil fields studies by Weaver was 12.4 per cent and he calculated that the rate of return for a typical 5,000 acre Gulf tract with a 30 year production life is 13.7 per cent. Another study * found that offshore operations in the Gulf of Mexico typically earn a return of 8.2 per cent, including losses on unsuccessful ventures. Since we include both successful and unsuccessful ventures, an 8.0 per cent rate of return is used in the base case.

Price (P)

The attractiveness of exploratory activity is sensitive to the expected prices for oil and natural gas. The current price of domestic oil ranges from about $5.25 to $10.00 per barrel. Domestic prices reflect U.S. oil import policy and world prices (themselves subject to government tax policy). Given the current energy shortages and the policies of Middle Eastern nations, high long-term prices appear inevitable. We use $5.00/bbl. in the base case. While this figure is low, given the sharp increases within the past 6 months, it is substantially higher than prices about one year ago, and allows us to illustrate that, even under conservative price assumptions, offshore prospects are very attractive.

The price of natural gas has risen sharply, since the FPC has permitted wellhead field price increases. Studies suggest that the equilibrium wellhead price for natural gas is at least $.50/MCF. Prices last summer exceeded $.65/MCF. We use gas prices of $.65 in the base case.*

We assume that the typical tract possesses both oil and natural gas, and that the oil-gas ratio corresponds to the ratio for tracts in the Gulf of Mexico as a whole. Thus, the price of hydrocarbons on an oil equivalent basis becomes $5.38/bbl, based on $5.00/bbl for oil and $.65/MCF for natural gas.

Tax Parameters (c, d, x, f)

The corporate tax rate (c) currently is 50 per cent and the rate of percentage depletion (d) is 22 per cent. The fraction of dry hole costs which can be expensed immediately is 100 per cent. These values are used in the base case.

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* The Role of Petroleum and Natural Gas from the Outer Continental Shelf in the National Supply of Petroleum and Natural Gas, U.S. Department of Interior, Bureau of Land Management, Technical Bulletin No. 5, 1970.

** We selected a price higher than the previous equilibrium level for two reasons: (1) future bidding rests on future price expectations which are expected to be higher; and, (2) the previous equilibrium level does not reflect the impact on costs of recent environmental regulations.

All intangible expenses may be expensed immediately. We assume that 72 per cent of drilling costs are eligible for deduction as intangibles and that the remainder must be capitalized.

The Royalty Rate (r)

The current royalty rate for oil and natural gas sales is .167. This rate is used in the base case.

Recoverable Reserves (R)

The estimate of recoverable reserves represents the total production expected during the operating life of the reservoir. It equals current estimates of proved reserves and cumulative production. At the time of abandonment, recoverable reserves equal cumulative production, because proved reserves have been depleted and equal zero. In the base case, we assume that the 5,000 acre tract will produce 63,787,822 equivalent barrels of output and use this figure as the estimate of recoverable reserves.

The Cost of Exploratory and Developmental Wells (W)

We assume the typical 5,000 acre tract requires 35 wells for development. The cost of offshore exploratory wells depends primarily upon their depth and distance from shore. A study of three exploratory wells with depths ranging from 13,000 to 16,000 feet, drilled from a jack-up rig in 300 feet of water 50 miles from shore, showed their average cost (in 1973 dollars) is about $550,000.

Development wells are drilled from vessels or platforms. The cost of a platform capable of supporting 14 to 24 producing wells in 200 to 250 feet of water is about $4 million. Three platforms would be typical for a 35-well drilling program.

The cost of the development wells depends primarily on the depth of the hole and whether it is straight or directional. The high cost of offshore platforms encourages operators to substitute directional platform drilling for platforms. Because of the contours of the Gulf of Mexico, wells in water depths up to 600 feet can be completed by directional drilling from fixed platforms in 300 feet of water. Platform placement, however, is an important factor in minimizing the incremental costs of increased directional drilling. The current average cost of 12 wells - 9 of which are directionally drilled - ranging in depth from 9,000 to 12,500 feet would be $350,000 per well.

Historical records of offshore drilling show that an average of 20 to 25 per cent of total wells in a typical drilling program are exploratory and the remainder are developmental. For our base case we thus assume that the typical 35-well program is composed of 8 exploratory wells drilled from a jack-up and the remaining 27 are drilled from a fixed platform. We assume that exploration costs, including the cost of the jack-up rig, equal $550,000 per well, and development costs including the cost of the fixed platforms total about $750,000 per well in the base case. (The costs of the fixed platform are approximately $400,000 per developmental well.) This leads to a weighted average cost per well of about $700,000.

Wells Drilled Per Barrel of Recoverable Reserves (B)

Using 63,450,280 equivalent barrels as estimated recoverable reserves for the typical 5,000 acre offshore tract, and assuming an operation of 35 wells (exploratory and developmental), results in a ratio of one well per 1,812,865 barrels of equivalent recoverable reserves.

Dry Hole Costs (H)

Accurate data on the dry hole costs of producing reservoirs are difficult to obtain because offshore producers sometimes classify potentially productive wells as dry holes to reduce information available to competitors bidding on adjacent tracts. Thus, the success ratio for offshore exploratory wells probably is understated. Published estimates suggest it is about 20 per cent, yielding about two successful wells and six dry holes in our base case of an 8 exploratory well program. The success rate for developmental wells is much higher. We assume that 90 per cent of developmental drilling costs are for producing wells. (It is ambiguous to speak of dry and successful developmental wells, because an initial developmental dry hole may subsequently result in production.) Assuming 6 dry exploratory wells at $550,000 per well yields a cost of $3,300,000. Ten per cent of developmental drilling costs ($750,000 x 27) is $945,000. Total dry hole costs are $4,245,000.

The costs of geological and geophysical exploration are included in the dry hole cost category in our analysis. We estimate these costs total about $1.5 million in the typical 5,000 acre tract and use this figure in the base case. The total dry hole costs in our base case thus total $5,745,000. This equals $.09 per barrel of recoverable reserves.

The Probability of Commercial Production (Y)

In 1970, 116 tracts were leased in Federal offshore lease sales. As of this summer, 47 have resulted in successful exploratory drilling. This suggests that the probability of commercial production is about 40 per cent. We believe that the success rate probably will decline in tracts leased in future sales because:

- the tracts already leased have been the most promising; and

- future tracts leased will tend to be in deeper waters, where larger quantities of reserves will be required to justify establishing commercial production facilities.

Thus, the probability of commercial production is assumed to be 30 per cent in the base case.

The Decline Rate (A)

The production curve for offshore tracts typically increases for five to seven years and then declines. The decline rate represents the aggregate production from all reservoirs in different stages of drilling, development, and workover.

To minimize the complexity of our model, we assume a constant decline rate in the base case. Thus, peak production is assumed to occur in the first year of the producing life of the tract. To offset the upward bias in the rate of return resulting from this assumption, we assume all development costs also occur in the initial year. Assuming cumulative production totaling 63,450,280 barrels (for a 30-year producing life) and peak production of 3,493,978 barrels (which we move to the first year) yields a decline rate of six per cent.

Operating Costs per Barrel (O)

Weaver estimates that total operating costs for the typical offshore tract with a 30-year producing life are $42,421,704. This includes labor, oil and gas transportation, surface equipment maintenance, downhole-workover expenses, radio and telephone expenses, administration and overhead. Total production equals 63,450,280 barrels of oil, condensate and gas on an oil equivalent basis. Operating costs per barrel thus equal $.67. To account for inflation, we use operating costs of $.75 per barrel in the base case.

Expected Present Value in the Base Case

Our values for each variable and the derivation of the Expected Present Value are shown in Exhibit 3 on the following page. The Expected Present Value in the base case equals $.20 per equivalent barrel. We assume that the base case tract of 5,000 acres contains oil and gas totalling 63,450,180 equivalent barrels. Thus, the total bonus payment for the tract derived from our model in the base case equals $12,690,050 ($.20 x 63,450,280). This is equivalent to a bonus payment of $2,538 per acre.

Our base case estimate of an average bonus payment of $2,538 per acre falls within the range of average bids in offshore lease sales during the past several years. The average bonus bids per acre in three recent sales are shown in Table on the next page.

EXHIBIT 3

VALUES FOR EACH VARIABLE AND THE EXPECTED PRESENT VALUE IN THE BASE CASE FOR AN OFFSHORE FIELD

Category	Variable	Value in Base Case
Tax and Leasing Policies:	Corporate tax rate (C)	.50
	Rate of percentage depletion (d)	.22
	Royalty rate (r)	.167
	Fraction of dry hole costs which can be expensed immediately (f)	1.00
	Fraction of exploratory and development well costs which can be expensed immediately (x)	.72
Economic Conditions:	Cost of capital (I)	.08
	Price per equivalent barrel of output (P)	\$5.38
Characteristics of the Potential Drilling Site:	Probability of commercial production (Y)	.30
	Decline rate (A)	.06
	Operating costs per barrel of output (O)	\$ .75
	Wells drilled per barrel of recoverable reserves (B)	$.55 \times 10^{-6}$
	Weighted average costs per well of exploration and development costs (W)	$\$ .7 \times 10^{6}$
	Dry hole costs per barrel of recoverable reserves (H)	\$ .09
	Recoverable reserves (R)	63,450,280

Solving for EPV per barrel yields:

$$EPV = .30\left\{\left[\frac{(1-.50+.50x.22)(1-.167)}{.06+.08}x5.38x.06\right]-\left[\frac{(1-.50)x.75x.06}{.06+.08}\right]\right.$$

$$\left.-\left[(1-.50x.72)x.7x10^{6}x.55x10^{-6}\right]\right\}-(1-50x.1.0)(1-.30)x.09$$

$$EPV = \$.20$$

TABLE 15

AVERAGE BONUS PAYMENT BID PER ACRE IN THREE RECENT OCS LEASE SALES *

Date of Sale	Average Bonus Bid Per Acre
September 12, 1972	$ 2,018
December 19, 1972	$ 3,108
June 19, 1973	$ 2,908

Sensitivity Analyses

The mathematical model outlined in the previous section can be used to simulate the effects of various policy changes, costs, and economic scenarios on the Expected Present Value of offshore drilling sites. Our hypothesis is that under a reasonable range of Federal policies, economic scenarios, and costs, the Expected Present Value of offshore tracts will remain positive, and firms will bid for offshore drilling rights. The effect of public policies which reduce the Expected Present Value of offshore tracts will only reduce the size of the bonus payment. A combination of extremely adverse circumstances is required to result in a negative (or zero) Expected Present Value.

We use four sensitivity analyses to test our hypothesis:

- In the area of tax policy, elimination of percentage depletion and the expensing of intangible drilling costs;
- In the area of economic conditions, a twenty per cent fall in price of hydrocarbons on an equivalent barrel basis;
- In the area of operating conditions, a 50 per cent increase in exploratory and development well costs, coupled with a 33 per cent increase in operating costs and a 44 per cent increase in dry hole costs; and,
- The most adverse case, combining the three changes listed above simultaneously.

In the first three cases, the Expected Present Value of the typical offshore drilling site remains positive. When all three changes are considered simultaneously,

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* Source: United States Department of Interior, Bureau of Land Management. Outer Continental Shelf Statistical Summary.

the Expected Present Value does become negative. Thus, the only set of policy, economic and cost changes which would lead to a negative Expected Present Value for a typical tract is a combination of severe tax changes, price declines, and cost increases. Even in this case, some offshore sites would continue to be drilled because our base case defines a typical tract, not the more profitable tracts. Thus, some tracts probably would continue to have positive Expected Present Values under the adverse conditions we tested, though the typical tract does not.

We conclude that our hypothesis has been proven. The model shows that operators will continue to bid on acreage at OCS lease sales because offshore exploration remains more promising than onshore exploration, unless a combination of extremely adverse policy, economic and operating conditions exist. Thus, under a reasonable range of alternative public policies, only the amount of the bonus payment will be affected (as long as OCS lease sales are held). The effects of each sensitivity analysis on the Expected Present Value per barrel and resulting lease bids per acre are shown in Table 16. Each sensitivity analysis is discussed in greater detail in the following paragraphs.

Tax Policy Changes

The principal tax policies affecting the petroleum industry are the expensing of intangibles, the expensing of dry holes, and percentage depletion. The rate of percentage depletion was changed from 27 per cent to 22 per cent as part of the 1969 Tax Reform Act. Any further lowering of the rate of percentage depletion would probably lead oil exploratory firms to assume that percentage depletion would be eliminated altogether. If percentage depletion were eliminated, oil producers would compute their tax liability using cost-based depletion. Cost-based depletion is roughly equivalent to a four per cent rate of percentage depletion.

Elimination of percentage depletion would probably be accompanied by an elimination of the expensing of intangibles and allow for the recovery of intangibles drilling costs through cost-based depletion.

We assume that any tax changes toward the petroleum industry would not affect the provision for the immediate expensing of dry holes. Most tax reform debates in the area of petroleum taxation have concentrated on percentage depletion and the expensing of intangibles rather than the expensing of dry hole costs.

The model indicates that such a tax policy change would reduce the Net Expected Present Value of offshore leasing sites by 50 per cent.* This is probably

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* This result is similar to the effects of depletion using other models. Spann, Erickson, and Millsaps estimated that elimination of percentage depletion and the expensing of intangibles would increase the user cost of committing funds to petroleum exploration by 48 per cent. (Robert M. Spann, Edward W. Erickson, and Stephen W. Millsaps, "Percentage Depletion and the Price and Output of Crude Oil," Committee on Ways and Means, U.S. House of Representatives, Panel Discussions, General Tax Reform. February 26, 1973.) A similar conclusion is contained in the statement of P. O. Steiner during the 1959 Tax Reform Hearings.

TABLE 16

THE EFFECT OF THE FOUR SENSITIVITY ANALYSES ON THE EXPECTED PRESENT VALUE PER BARREL AND LEASE BID PER ACRE*

Assumptions	Expected Present Value Per Barrel of Reserves	Average Lease Bid Per Acre	Percentage Decreases From Base Case
Base Case	$.20	$2538.00	--
Sensitivity Analyses:			
(1) Elimination of percentage depletion and expensing of intangibles.	.10	1289.00	50%
(2) Twenty percent price decline.	.12	1523.00	40%
(3) A 50 percent increase in exploratory and developmental well costs, a 33 percent increase in operating costs, and a 44 percent increase in dry hole costs.	.13	1650.00	35%
(4) Numbers (1), (2), and (3) simultaneously	-.05	--	--

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*Assumes a typical tract of 5,000 acres with ultimate recovery of 63,450,280 equivalent barrels of oil and gas.

an overstatement of the effects of these tax policy changes on the cost of offshore drilling. The model assumes that, in the absence of percentage depletion, petroleum firms would not be eligible for the investment tax credit of acceleraged depreciation.* To the extent that some form of accelerated depreciation or investment tax credit similar to those available to manufacturing industries would be extended to petroleum exploration, development, and production, the model overstates the effects of tax policy changes on offshore drilling incentives.

The bias does not alter the implications of the model. If tax policies are changed, the typical offshore tract will continue to have a positive Expected Present Value. Thus, tax policy changes, even of the magnitude simulated here, will not eliminate the incentives for offshore drilling.**

Price Changes

The prices of oil and gas used in the base case ($5.00 per barrel of oil and $0.65 per MCF of gas) represent expected future prices on which lease bidding decisions are made. The assumptions implicit in these price expectations are that oil exporting nations are successful in maintaining recent high prices for crude oil and that natural gas field prices are either deregulated or that field price increases in recent years are continued, at least on a limited basis.

Other economic and public policy scenarios are possible. Some observers feel that action by the U.S. and other consuming nations, combined with the inherent instability of cartels, could lead to an erosion or stabilization in the price of foreign oil. If such a scenario did occur, there would be a downward adjustment in the expected price of crude oil which would be reflected in offshore lease bids.

With regard to natural gas, current lease bids probably are being made on the basis of current intrastate natural gas prices and recent increases in the price of interstate natural gas allowed by the Federal Power Commission. Alternative policy scenarios also are conceivable. The trend toward increased prices of natural gas could be reversed or slowed down by regulatory decisions. Instead of allowing natural gas prices to increase, policy could shift towards end use controls on natural gas coupled with the use of SNG and LNG to supplement domestic production.

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* In its present form, the percentage depletion and the expensing of intangibles provisions are similar to a high rate of accelerated depreciation for tax purposes.

** Such a tax policy change might eliminate some drilling sites, however. The model pertains to a typical tract. Drilling sites which have much lower than average Expected Present Values might have negative Expected Present Values if tax policies were changed. The average tract would remain profitable.

In such a case, producers might revise their price expectations downward.*

In order to simulate the possible effects of downward adjustments in oil or gas prices, we assume a 20 per cent decline in the price of an equivalent barrel of oil, from $5.38/bbl to $4.30/bbl. This results in a 40 per cent decline in the Expected Present Value of the typical tract.** Thus, price declines can be expected to result in lower bonus payments but operators would continue to bid for offshore tracts. No simulations which employ specific assumptions about changes in the price of oil or gas alone were conducted. The price decline simulated here is sufficiently broad to cover a wide range of alternative price declines for particular fuels. We feel that no specific price changes in one fuel alone would be more severe than a 20 per cent overall price decline in terms of equivalent barrels of oil.

Should relative oil and natural gas prices change, the gas-oil ratio on which the equivalent barrel price is calculated also would change. While the distribution of oil and gas deposits is given by nature, the intensity with which specific sites are developed is determined by the relative prices of oil and natural gas. An increase in the price of oil relative to the price of natural gas would lead to:

- more intensive development of tracts with a low gas-oil ratio and less intensive development of tracts with a high gas-oil ratio; and,
- longer well lives on tracts with low gas-oil ratios relative to well lives on tracts with high gas-oil ratios.

Operating Cost Changes

The Expected Present Value calculations made in the base case and the preceding simulations use cost parameters typical of current drilling costs and technology. Changes in costs can be expected in the future. In order to assess the effects of adverse cost changes on the model, Expected Present Values were calculated for a set of costs in excess of current cost levels. The sensitivity analysis assumes a 50 per cent increase in exploratory and developmental well costs, a 33 per cent increase in operating costs, and a 44 per cent increase in dry hole costs.

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* The alternative scenario, that of continued increases in world oil prices and a deregulation of natural gas prices, is not simulated explicitly. Such a scenario could lead to expected prices per equivalent barrel of oil which equal or exceed the current price of new oil...about $8.00 per barrel. At this price, the typical tract has a positive Expected Present Value even if both tax and cost changes are considered. (The Expected Present Value is positive at a price as low as $6.46 per equivalent barrel -- 20 per cent higher than the base case -- even under adverse tax and cost changes.)

** The percentage decline in Expected Present Value exceeds the percentage decline in prices due to: (1) the effects of tax policy, (2) discounting, and (3) the fact that costs are being held constant as revenues are being reduced.

The effect of these cost increases is to reduce the Expected Present Value of the typical drilling site by 35 per cent. Since the Expected Present Value remains positive, operators would continue to bid for OCS acreage, but the bonus payments would be reduced.

Simultaneous Tax Policy Changes, Price Decline, and Cost Increases

The final sensitivity analysis was a combination of the preceding three analyses. It represents the most adverse case, where tax allowances are reduced, prices decline, and costs increase. These circumstances result in a negative Expected Present Value for the typical tract. Thus the typical tract would be unprofitable even with a zero bonus payment, and there would be no bids for the typical tract in a lease sale.

Even under the conditions of our most adverse case, some drilling sites might remain profitable. In previous lease sales, some tracts have commanded much higher than average lease bonuses.* These particularly favorable tracts might remain profitable in the event of a simultaneous price fall, tax change and cost increase, whereas the typical tract does not.

The circumstances postulated by our most adverse case are unlikely to occur. Oil and natural gas prices are, to a large extent, determined by tax policies and cost conditions. In the event of adverse tax and cost changes, prices probably would increase rather than decline.

We conclude, therefore, that for most foreseeable public policies - short of direct restrictions on OCS lease sales - and a wide variety of economic and cost conditions, offshore sites will remain profitable and attract bidding by prospective drillers. The size of the bonus payment will adjust to reflect the bidders' perception of Expected Present Value. As adverse conditions diminish expectations, bonus payments will be reduced.

The Expected Present Value of an Onshore Drilling Site

In order to develop an estimate of the Expected Present Value of a potential onshore drilling site, the model was applied to the Jay field in Florida. We selected the Jay field because it is one of the few recent giant field discoveries onshore in the past five years. Thus, its size and proximity to Gulf offshore fields provide an appropriate comparison to the typical offshore site we analyzed. (A giant field has ultimate recovery of at least 100,000,000 barrels of oil.) The Jay Field was discovered in 1970 and ultimate recovery is 378,000,000 equivalent barrels. No attempt was made to develop a typical onshore site because onshore exploration and development costs differ vastly between fields.

Exhibit 4 shows the value for each variable and the expected present value per barrel for the Jay field. Data were obtained from industry records and publications which provided data specifically for the Jay field.

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* For example, the average winning bid per acre was $2,908 in the OCS lease sale of 6/19/73. Winning bids on all tracts ranged from under $100.00 on one tract to more than $12,000 on other tracts.

EXHIBIT 4

VALUES FOR EACH VARIABLE AND THE EXPECTED PRESENT VALUE FOR AN ONSHORE FIELD

		Value for the Jay Field
Tax and Leasing Policies:	Corporate tax rate (c)	.50
	Rate of percentage depletion (d)	.22
	Royalty rate (r)	.125
	Fraction of dry hole costs which can be expensed immediately (f)	1.00
	Fraction of exploratory and development well costs which can be expensed immediately (x)	.40
Economic Conditions:	Cost of capital (I)	.08
	Price per equivalent barrel of output (P)	$5.41
Characteristics of the Potential Drilling Site:	Probability of commercial production (Y)	.11
	Decline rate (A)	.07
	Operating costs per barrel of output (O)	$.50
	Wells drilled per barrel of recoverable reserves (B)	$.24 \times 10^{-8}$
	Weighted average costs per well of exploration and development costs (W)	$\$1.15 \times 10^{6}$
	Dry hole costs per barrel of recoverable reserves (H)	$.01
	Recoverable reserves (R)	378,000,000

Solving for EPV per barrel yields:

$$EPV = .11\left\{\left[\frac{(1-.50+50\times.22)(1-.125)\times5.41\times.07}{.07+.08}\right]-\left[\frac{(1-.50)\times.50\times.07}{.07+.08}\right]-\left[(1-.50\times.40)\times.24\times10^{-8}\times1.15\times10^{6}\right]\right\}-(1-.50\times1.0)(1-.11).01$$

EPV = $.10

Three tax and leasing policy variables are different for the Jay field than the base case offshore field:

- the royalty rate (r) onshore is .125 compared to .167 offshore;
- a state severance tax of 5 percent applies; this is reflected by a 5 percent reduction in the price per equivalent barrel of output (p), which thus is assumed to be $5.41 for the Jay field.
- the fraction of exploratory and development well costs which can be expensed immediately remains at .72. However, for the Jay field, we have included the costs of a sulfur treatment plant in well costs. Because the cost of the sulfur treatment plant must be capitalized, the estimated fraction of well costs which can be expensed immediately for the Jay field -- including the cost of the sulfur treatment plant -- becomes .40.

The cost of capital (I) remains unchanged at .08. The price per equivalent barrel of output (P) is assumed to be $5.41. As noted above, this reflects a 5 percent state severance tax. This is based on a price of oil of $5.00 per barrel and a price of gas at $.50/MCF. The price of gas differs for the Jay field from the offshore base case to reflect more closely the actual price received for Jay field natural gas.

All of the drilling site characteristics are changed:

- The probability of commercial production (Y) is assumed to be .11 for the Jay field, as compared to .30 for the typical offshore field. This reflects the lower drilling success rates for onshore sites, and is a generally accepted success ratio for onshore rank wildcatting.
- The decline rate (A) is .07 percent. The Jay field is expected to have a 25-year producing life. Peak production is assumed to occur in the first year of the producing life of the tract and the decline rate is assumed to be constant. Cumulative production of 378,000,000 barrels for 25 years and peak production of 25,000,000 barrels in the first year, yields a decline rate (A) of .07.
- Operating costs per barrel (O) are assumed to be $.50. For the offshore base case, operating costs per barrel were estimated to be $.75/bbl for wells producing about 500 barrels per day. Average onshore costs are about $.70 - $.75/bbl. Both of these estimates are too high for the Jay field. Offshore costs include many functions not required by onshore fields, such as crew maintenance, communications, etc. The onshore average includes many high cost stripper

wells. Wells on the Jay field average about 1,000 barrels per day production, so costs should be low. But costs of the desulfurization plant must be included, so we conclude that \$.50 is a reasonable estimate of Jay field operating costs per barrel.

- Wells drilled per barrel of recoverable reserves (B) are $.24 \times 10^{-8}$.

- Weighted average costs per well of exploration and development costs (W) are \$1.15 million. Ten successful exploratory and 80 development wells have been drilled to date. The average cost per development well is \$667,000. To this cost must be added the cost of a sulfur treatment plant necessitated by the joint production of hydrogen sulfide gas. Prorating the cost of the sulfur treatment plant yields a cost per development well of \$1,250,000. The total cost of development wells thus equals \$100 million. The ten exploratory wells are assumed to cost \$325,000 each for a total cost of \$4,250,000. The total cost of the exploratory and development wells thus is \$103,250.000, or about \$1.15 million per well.

- Dry hole costs per barrel (H) are \$.01. In the opinion of the Florida Bureau of Geology, approximately ten exploratory dry holes were drilled in the specific search for Jay field. However, in the general Mesozoic trend exploration play, a much larger number of rank wildcats have been drilled. The Jay field is the outstanding exploratory result of that activity. Therefore, use of the general success ratio for onshore rank wildcats drilling (.11) and a total dry hole count directly attributable to Jay of ten wells understates the dry hole cost that might reasonably be attributed to the Jay field, and, correspondingly, overstates the profitability of Jay as an example of the kind of exploration involved in such activity as the general Mesozoic trend play. Dry hole costs per well are estimated at \$325,000.

- Recoverable reserves are 378 million barrels of equivalent output.

The EPV per barrel of the Jay field is \$.10. This is equivalent to an EPV per acre of \$1,222. (The Jay field comprises approximately 30,853 acres.) Thus, our analysis suggests that a firm would have been willing to pay a bonus of up to \$1,222 per acre for the Jay field in a lease sale, based on assumptions about the field which closely approximate actual characteristics. This compares to an EPV of \$2,538 per acre for the typical offshore field we analyzed, suggesting that the most attractive onshore fields are not as promising as the average offshore field.

Our calculation of the EPV for the Jay field probably is overstated, as discussed earlier, because the number of dry holes is not accurately known. Actual dry hole costs may be as much as \$.10 per barrel instead of \$.01. Further, we include no estimate of geophysical and geological exploration costs, because of the difficulty of estimating this figure. The impact of this omission on the EPV, however, is very slight, relative to the effect of our underestimation of dry holw costs.

The EPV is very sensitive to key parameter assumptions, such as the probability of commercial production. We used .11 for the Jay field, because .11 represents the typical onshore rank wildcat exploration success ratio. For the typical offshore field, .30 was used to reflect the higher success rates offshore. Using .30 for the Jay field would result in an EPV per barrel of $.30, or $3,666 per acre.

Drilling Decisions of Private Firms

This section digresses briefly to discuss several theories of how private firms make their drilling decisions. It is intended to illustrate the appropriate use and limitations of the Expected Present Value model we developed in understanding the drilling decision. The model used to simulate the drilling decision in this study measures the Expected Present Value of a potential site based on economic and geological considerations. However, the decision of which drilling prospects to pursue in the real world is very complex and based on large uncertainties. Further, the objectives of the firm may vary greatly among drilling sites. At any point in time, firms pursue a wide range of exploratory activities -- which can be likened to an investor's portfolio of holdings -- with varying objectives, time frames, risks, and expected returns.

Our analysis shows that operators will be willing to pay bonus payments for offshore drilling rights whenever acreage is offered for lease under a wide range of economic conditions. It does not suggest that firms will seek only to drill sites with equal Expected Present Values, or the highest Expected Present Values available, (given the constraint of funds available for exploration) or any drilling site combination which maximizes the firm's total Expected Present Value. This is because economic considerations reflected in the Expected Present Value are modified by other factors.

Many studies have addressed the issue of how exploration decisions are made by private firms. Most focus on the hypothetical response of firms to specified market and risk conditions. Only one major study* surveys a sample of firms (4 majors and 10 independents) to assess how drilling decisions are made in the real world. The study results suggest that operators rarely rely on formal, stated criteria or modeling to evaluate prospects. Instead, they estimate the value of the site subjectively on the basis of personal experience and intuition.

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*C. Jackson Grayson, Jr., Decisions Under Uncertainty: Drilling Decisions of Oil and Gas Operators, 1960.

Grayson notes that drilling decisions offer a classic uncertainty problem. Even though geology and geophysics provide certain information about the potential drilling site, only one of nine new field wildcats finds any oil. However, to be profitable, on the average a well must discover at least one million barrels. The chances of striking a well this size are much smaller:

Chance	Estimated Recoverable Reserves
1 in 42	1 million barrels or more
1 in 158	10 million barrels or more
1 in 427	25 million barrels or more
1 in 706	50 million barrels or more

The range of factors any operator must consider are represented in the following questions:

Geological factors:

1. What are the chances of finding oil at this particular location?
2. How much oil is there likely to be?

Economic Factors:

1. How much will it cost to find out?
2. How much can it be sold for?
3. How much will it cost to produce?
4. How fast can it be produced?
5. What will be required to develop the property if the well is successful?

Personal factors:

1. Are there enough funds available to drill this well?
2. Will drilling this well help me or my firm achieve a desired goal?

Where the uncertainties and complexities are greatest -- new field and new pool wildcats -- most operators feel it is impossible to express judgment about the uncertainty of each factor empirically. Even if it were possible, they don't know how the values assigned to each factor should be incorporated into the decision. Thus, the usual decision process on a wildcat is for the decision maker to study the geological maps and reports, listen to the geologists' opinions, think (somehow integrating all other uncertainties and complexities), and reach a decision intuitively. For development wells, operators generally try to assign numbers to the decision factors and decide at least partially on the basis of formally stated criteria.

Adelman* offers a theory which supports these findings. He suggests that the underground stock must be considered at two stages: (1) oil-in-place, which is found by exploratory drilling, and (2) reserves, which are "carved out" and readied for production by developmental drilling. This distinction is crucial because development is an investment with limited uncertainty where past cost data can be used to estimate future costs. In contrast, exploration is a probe of the unknown with small probabilities of future success. Thus past successes or costs are of uncertain or little relevance in judging whether a new exploratory effort is worth making.

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* M. A. Adelman, *The World Petroleum Market*, Resources for the Future, Inc., 1972.

In the post war era, exploratory efforts resulted in few large field discoveries. This factor, combined with improved technology, made intensive development more and more attractive relative to exploration. This is confirmed by the high bids for offshore leases. The harder it became to find large new fields, the greater the premium on those places where there is still hope of making good finds. The rising price of offshore leases during an era until recently characterized by stable oil prices suggests that developing and producing costs have gone down. New flush fields probably are cheaper to develop than years ago, and would allow the operator larger profits. In the U.S., about 200 fields of a total of about 10,000 account for more than one-half of total reserves. The effects of finding a giant field are therefore very great.

One recent study* has focused on the competitive bidding decision for offshore and Alaskan drilling rights in an effort to explain why offshore operations have not been exceptionally profitable for the industry as a whole. The high bonus payments paid by firms to obtain offshore and Alaskan drilling rights would suggest that very lucrative operations are anticipated. But, as we have seen, estimates of the profitability of offshore operations have been modest. The authors focus on the very large divergence in bonus bids of serious competitors in recent sales to explain this apparent paradox.

Firms base their bonus bids primarily on expectations of marketable reserves. The great divergence of bonus bids in recent lease sales suggests either that competitors had access to different geophysical data or that they interpreted the same data differently. Even when the same geophysical data are used, widely divergent bonus bids have resulted. In the 1969 Alaska North Slope sale, for example, Atlantic Richfield and Humble Oil, who are equal partners in many exploratory projects and essentially had the same geophysical information, bid against each other on 55 tracts. At one extreme, Humble's bid was only 3 percent of Atlantic Richfield's bid; at the other, Humble's was seventeen times as great as Atlantic Richfield's bid and between these extremes was a smooth gradation of ratios.

Each bidder's reserve estimates can be assumed to be either too high or too low, and usually they are not even close to actual (unknown) reserves. Generally, the bidder who "sees" the largest reserves also will "see" the greatest dollar value and thus offer the highest bid. In other words, in competitive bidding, the winner tends to be the bidder who most overestimates tract value. While each bidder's evaluations of tracts may be correct on average over the whole range of tracts on which he bids, he tends to win a biased set of tracts -- those for which he has overestimated reserves.

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* William M. Campbell, Edgar C. Capen, and Robert V. Clapp, "Competitive Bidding in High Risk Situations, "National Institute for Petroleum Landmen, Vol. 13, 1972.

An example illustrates this process. Assume a 10 tract sale, that all tracts will be productive and, after exploratory drilling costs, each will be worth $10 million at a 10 percent discount rate. Each competitor in the sale correctly estimates the total value of the sale acreage, but may be too high or low on any one tract. Also assume that to protect himself from risks and uncertainties, each competitor bids one-half his value estimate.

Table 17 reflects the sale if only Company A bids. He correctly estimates that the 10 tracts are worth $100 million and bids one-half this amount, so the sum of his bids is $50 million. He wins all tracts since there is no competition. Since he pays $50 million for what is worth $100 million (at a 10 percent discount rate) his after tax rate of return will be 17 percent. (Estimated by authors from studies of cash flow in typical operations.)

Table 18 shows what happens if the number of bidders increases to four. Company A's undervaluated tracts are leased to competitors, leaving Company A only with Tract 8, which was evaluated at $35 million (but worth only $10 million). The government's share has increased to $92 million -- the sum of all high bids. Company A's rate of return drops to 5 percent, whereas the average for the industry drops to 11 percent.

Some analysts suggest that reserves on Federally leased lands generally have been underestimated by industry and the government, resulting in lower competitive bids overall than their true value would warrant. However, the rate of return of offshore operations -- estimated at about 8 percent by one author* compared to the overall rate of return for petroleum companies in Fortune's top 500 of 9.4 percent -- suggests that the analysis presented may be a truer reflection of reality.

Impact of Other Factors on Offshore Exploration

Numerous Federal policies and other factors are not readily amenable to quantitative sensitivity analyses using the model we developed. These include:

- co-location of refineries and pipelines;
- the gas/oil ratio;
- conservation regulation with respect to depth-acreage allowable schedules; and
- the rate at which offshore tracts are offered for lease by by the Federal government and the states.

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* U.S. Department of the Interior, Bureau of Land Management, The Role of Petroleum and Natural Gas from the Outer Continental Shelf in the National Supply of Petroleum and Natural Gas, Technical Bulletin No. 5, May, 1970.

TABLE 17

ILLUSTRATION OF COMPETITIVE BIDDING RESULTS WHEN ONE FIRM BIDS

Tract Number	A's Bid*
1	$ 1.9
2	$ 5.6
3	$ 2.6
4	$ 3.4
5	$ 3.7
6	$ 5.2
7	$ 1.9
8	$17.5
9	$ 3.9
10	$ 4.3

	Company A	Industry
Winning Bids*	$ 50	$ 50
Value of Acreage Won	$100	$100
Excess of Value over Winning Bids	$ 50	$ 50
Rate of Return	17%	17%

Source: William M. Campbell et. al., op. cit.

TABLE 18

ILLUSTRATION OF COMPETITIVE BIDDING RESULTS WHEN FOUR FIRMS BID

Tract Number	A's Bid	B's Bid	C's Bid	D's Bid
1	$1.9	$3.8	$5.7	$6.5*
2	5.6	5.1	3.1	8.3*
3	2.6	4.0	2.6	7.8*
4	3.4	4.9	6.5*	6.4
5	3.7	0.6	9.8*	3.3
6	5.2	4.2	9.8*	2.2
7	1.9	5.9*	4.0	3.3
8	17.5*	4.5	1.5	5.0
9	3.9	1.8	3.3	4.5*
10	4.3	15.2*	3.7	2.7

	Company A	Industry
Winning Bids	$17.5	$91.8
Value of Acreage Won	$10.0	$100.0
Excess of Value over Winning Bids	$-7.5	$8.2
Rate of Return	5%	11%

Source: William M. Campbell, et. al., op. cit.

Some qualitative judgement, however, can be expressed with regard to each of these factors.

Co-location of Refineries and Pipelines. Offshore Texas and Louisiana are well served by refineries and pipelines, making expansion of operations there attractive, relative to other regions such as Alaska and the Atlantic OCS. The CEQ report on the feasibility of offshore oil and gas production in the Atlantic Ocean emphasized that the environmental risk associated with development of onshore support facilities -- refineries, petrochemical complexes, gas processing facilities, and other service operations -- is at least as great as that resulting from oil spills.

Table 19 shows the distribution of crude refinery capacity by region and state and Table 20 shows the distribution of oil pipeline mileage. Texas and Louisiana account for about 38 percent of total U.S. crude refinery capacity and 33 percent of crude and product pipeline mileage. Pipeline mileage data are not published separately for offshore areas, but offshore Louisiana and Texas currently are served by several major oil and gas pipelines. Additionally, numerous pipeline projects for offshore Louisiana are being developed. One of these, the Stingray Pipeline System, is the costliest project to date anywhere in the lower 48 states. At an estimated cost of $150 million, 300 miles of natural gas pipeline will be built offshore. The pipeline will take off from an existing 49 mile long, 36 inch wide natural gas pipeline. It is expected to achieve two offshore landmarks -- a distance of 125 miles from shore and water depths of 600 feet.

The crude oil pipeline authorized for Alaska is estimated to cost about $2.5 billion. Permits are being sought for a natural gas pipeline and other Alaskan pipeline projects are being planned. None of these will be operational until the 1980's, so significant production from Alaska will not be available for at least a decade.

The Gas/Oil Ratio. The gas/oil ratio for the tract we examined was relatively low. The tract was assumed to be primarily oil producing. Many offshore tracts are primarily gas producers. The price of gas is likely to increase more rapidly than the price of oil. This would tend to make offshore exploration even more attractive than suggested by our analysis.

Conservation Regulations. Conservation regulation, with respect to depth-acreage allowables and market demand factors, has entered a new phase. The domestic industry generally has been producing at capacity for over a year. For example, Texas production allowables have been set at 100 percent for the past 25 months. There is no reason for state agencies to restrict production or promulgate any rules which are designed to reduce incentives for exploration. Conservation regulations are likely to continue to encourage high cost, offshore exploration relative to lower cost onshore exploration. Any changes in the regulations probably would make them more neutral with respect to the attractiveness of offshore exploration.

The Rate of OCS Leasing. The rate at which offshore tracts are offered for lease and the legal and environmental considerations which must be resolved prior to any lease sale are likely to be the controlling factors with respect to the rate at which

TABLE 19

OPERATING REFINERIES IN THE U.S.: STATE CAPACITIES AS OF JANUARY 1, 1974

Regions	Number of Plants	Crude Capacity (Barrels Per Stream Day)
East:		
Delaware	1	150,000
Georgia	2	15,130
Illinois	11	1,206,390
Indiana	7	588,050
Kentucky	3	167,000
Maryland	2	24,700
Michigan	6	172,974
Minnesota	3	198,000
New Jersey	5	646,131
New York	2	111,000
Ohio	7	606,500
Pennsylvania	11	729,215
Tennessee	1	30,000
Virginia	1	55,790
West Virginia	3	20,500
Wisconsin	1	38,000
Missouri	1	110,530
Subtotal	67	4,869,910
Southeast:		
Mississippi	5	289,700
Alabama	4	37,010
Florida	1	5,500
Subtotal	10	332,210
Southwest and South Louisiana and South Texas:		
Louisiana	18	1,733,180
Texas	40	3,896,560
Oklahoma	12	481,000
Arkansas	4	58,000
Kansas	11	418,050
Subtotal	85	6,586,790
West:		
California	34	1,894,800
Oregon	1	14,740
Washington	7	361,100
Utah	6	140,620
Wyoming	10	181,210
New Mexico	6	57,130
Colorado	3	57,920
Arizona	1	10,000
Hawaii	2	73,689
Montana	8	166,200
Nebraska	1	5,500
North Dakota	2	55,530
Subtotal	81	3,018,439
Alaska	4	69,020
Total	247	14,876,050

Source: Oil and Gas Journal, April 1, 1974, p. 84.

TABLE 20

CRUDE OIL AND REFINED PRODUCTS PIPELINE MILEAGE IN THE U.S.: STATE CAPACITIES AS OF JANUARY 1, 1971

Regions	Total Miles in Place
East:	
Maine	353
Delaware	3
Georgia	1,728
Illinois	11,019
Indiana	4,495
Kentucky	2,511
Massachusetts	242
Maryland	219
Connecticut	92
Michigan	3,744
Minnesota	2,955
New Hampshire	108
New Jersey	568
North Carolina	834
South Carolina	635
New York	1,673
Rhode Island	17
Ohio	6,909
Pennsylvania	8,291
Tennessee	629
Virginia	822
West Virginia	3,612
Wisconsin	942
Vermont	177
Missouri	6,295
Subtotal	58,873
Southeast:	
Mississippi	3,058
Alabama	1,237
Florida	87
Subtotal	4,382
Southwest and South Louisiana and South Texas:	
Louisiana	7,956
Texas	65,259
Oklahoma	22,308
Arkansas	2,397
Kansas	16,013
Iowa	3,884
Subtotal	117,822
West:	
California	9,868
Oregon	689
Washington	762
Utah	1,042
Nevada	328
Wyoming	6,644
New Mexico	5,941
Colorado	1,756
Arizona	1,071
Hawaii	
Montana	3,054
Nebraska	3,341
North Dakota	1,664
South Dakota	640
Idaho	640
Subtotal	37,440
Alaska:	87
Total	218,604

Source: U.S. Dept. of Interior, Bureau of Mines, Mineral Industry Survey, "Crude-Oil and Refined-Produced Pipeline Mileage in the United States, Jan. 1, 1971," Dec. 3, 1971.

offshore exploration and production takes place. The nature of these factors does not easily lend itself to quantitative analysis. However, no other factors -- with the exception of some severe disappointments with respect to the realization of anticipated reserves -- are likely to reduce the fundamental attractiveness of offshore areas to a point where exploratory activity voluntarily ceases.

IV

THE TRADE-OFF OF EXPLORATORY ACTIVITY ON THE MARGIN AMONG COMPETING ONSHORE AND OFFSHORE REGIONS

Regions Increasing Their Share of Exploratory Activity on the Margin

To assess which onshore and offshore regions are being traded on the margin, we reviewed the recent drilling experience of the competing onshore and offshore regions. We also reviewed the history of oil and natural gas reserve additions for each region.

Data on the annual number and footage of exploratory wells drilled by state are published by the American Association of Petroleum Geologists. However, data for offshore areas are shown separately from adjacent state totals only since 1966 so our analysis of exploratory drilling is limited to the seven-year period from 1966 to 1972 (except for the number of wells drilled, for which 1973 data are available).

Data on the total number of exploratory and development wells, footage drilled, and drilling expenditures are published annually on a joint basis by the American Petroleum Institute, the Independent Petroleum Association of America, and the Mid Continent Oil and Gas Association. While data on exploratory drilling only cannot be broken out from these reports, we review the data from 1960 to 1973 to obtain a longer term view of the role of offshore regions in overall drilling activity and to look at the rate of increase and distribution of drilling expenditures, which illustrate most dramatically the attractiveness of offshore regions. Because offshore drilling is much more expensive per foot drilled than onshore drilling, comparing only the number of wells or footage drilled fails to illustrate the disproportionate allocation of exploratory dollars offshore.

Tables 21 and 22 show the distribution of exploratory wells and exploratory drilling footage among regions from 1966 to 1972. During this period, the Gulf of Mexico's share of the number of exploratory wells drilled rose from 3.2 percent to 3.7 percent, and the West's share rose from 18.3 percent to 24.4 percent. The only other region whose share of exploratory wells did not decline during this period is South Louisiana and South Texas, which increased its share from 19.2 to 23.8 percent.

While each exploratory well drilled represents a gamble, exploratory drilling footage is a better method of assessing the trade-off among competing regions.

TABLE 21

PERCENTAGE DISTRIBUTION OF NUMBER OF EXPLORATORY WELLS DRILLED BY REGION, 1966 - 1973

	1966	1967	1968	1969	1970	1971	1972	1973
Total U. S. Exploratory Wells	10,313	9,059	8,879	9,701	7,693	6,922	8,357	8,008
Lower 48 Offshore Regions								
Gulf of Mexico	3.2%	4.1%	4.4%	3.2%	2.5%	4.4%	3.9%	3.7%
Pacific Coast	.1%	.2%	.3%	.2%	.2%	.2%	---	---
Lower 48 Onshore Regions								
East	20.4%	16.8%	14.5%	11.0%	11.9%	13.2%	11.0%	11.4%
Southeast	4.3%	4.3%	4.6%	4.3%	3.6%	3.8%	3.6%	4.3%
S. Louisiana and S. Texas	19.2%	15.1%	15.5%	17.4%	17.7%	16.6%	23.0%	23.8%
Southwest	34.0%	39.5%	35.9%	34.2%	33.7%	34.9%	32.2%	32.3%
West	18.3%	19.6%	24.4%	29.6%	29.7%	26.8%	26.3%	24.4%
Alaska	.4%	.4%	.2%	.1%	.8%	.1%	.1%	.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Source: 1966 to 1971 data are taken from the "U. S. Drilling Summary Reports" published annually in the American Association of Petroleum Geologists Bulletin.

1972 data are from the Oil and Gas Journal, Jan. 29, 1973, p. 103.

1973 data are from the Oil and Gas Journal, Jan. 28, 1974, p. 114.

TABLE 22

PERCENTAGE DISTRIBUTION OF EXPLORATORY DRILLING FOOTAGE BY REGION, 1966-1972

	1966	1967	1968	1969	1970	1971	1972
Total U. S. Exploratory Footage (000)	55,223	49,124	50,958	57,466	45,253	40,388	45,044
Lower 48 Offshore Regions							
Gulf of Mexico	7.1%	8.2%	8.6%	5.9%	4.5%	8.0%	5.4%
Pacific Coast	.2%	.3%	.5%	.2%	.3%	.4%	.1%
Lower 48 Onshore Regions							
East	7.0%	6.1%	5.7%	4.6%	5.1%	5.7%	6.0%
Southeast	6.2%	6.3%	6.2%	6.0%	5.3%	5.8%	8.2%
S. Louisiana and S. Texas	28.2%	25.8%	23.5%	23.9%	24.6%	23.6%	22.5%
Southwest	32.5%	33.1%	30.6%	30.6%	29.9%	30.9%	30.3%
West	18.0%	19.6%	24.5%	28.6%	28.9%	24.8%	27.2%
Alaska	.7%	.7%	.5%	.2%	1.4%	.1%	.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Source: "U. S. Drilling Summary Reports", published annually in the American Association of Petroleum Geologists Bulletin.

Regions which will expand significantly their share of total future exploratory effort are likely to be those in which large reserves are expected to lie in very deep reservoirs and heretofore, due to economic and technological constraints, have not been pursued. As average well depths increase, costs rise rapidly, constraining the total number of exploratory wells which can be drilled. Older producing areas, such as the East, have a substantially higher share of wells than of footage, because relatively shallow wells still are expected to yield successful drilling results. However, reserves anticipated are more modest than those anticipated from deep onshore and offshore exploratory drilling, where large reserves are required to support much more expensive exploratory and development operations.

In reviewing the changes in the share of exploratory drilling footage, the Southeast and the West were the only regions to increase their share. The West had the greatest increase, from 18.0 percent to 27.2 percent of total exploratory drilling footage.

In 1972, the Gulf's share of exploratory footage was 5.4 percent, reduced from 7.1 percent in 1966. However, the Gulf's share had exceeded the 1966 level in three succeeding years; the Gulf reached its highest share of exploratory drilling footage, 8.6 percent, in 1968. Exploratory activity in the Gulf is closely related to the timing of Federal lease sales, so the erratic nature of exploratory activity does not represent only producer interest. The surge of exploration in 1968, for example, followed a large Federal lease sale in offshore Louisiana of .7 million acres, the second largest lease sale held in the Gulf to that date.

Both the number and the footage of total exploratory wells declined during this eight-year period. Tables 23 and 24 show the number and footage of exploratory wells annually and the compound rate of change for each region. In 1966, 10,313 exploratory wells were drilled in the United States; by 1973, the number had fallen to 8,008. This represents a compound rate of change of -3.7 percent. The only region to show an increase in the number of exploratory wells drilled in 1973 over 1966 is the West, which experienced a compound rate of growth in the number of exploratory wells drilled of 0.6 percent during this period. The other region with a positive compound rate of change during this period was South Louisiana and South Texas, but the 1966 level was never reached in subsequent years. The region with the lowest negative compound growth rate was the Gulf of Mexico.

Total exploratory footage drilled in the U. S. declined at a compound rate of -3.8 percent from 1966 to 1972 -- from 55,223,000 to 45,044,000 feet. Two regions showed an increase in footage in 1972 over 1966 -- the West and the Southeast. Exploratory footage in the West increased from 9,[illegible] feet to 12,[illegible], representing a compound rate of growth of 2.8 percent. The Southeast showed a decline in the compound rate of growth of -1.8 percent. All other regions had a negative compound rate of growth which exceeded that of the total United States.

TABLE 23

NUMBER OF EXPLORATORY WELLS DRILLED BY REGION, 1966-1973

REGION	1966	1967	1968	1969	1970	1971	1972	1973	Compound Rate of Change
Lower 48 Offshore Regions									
Gulf of Mexico	332	374	392	314	191	305	324	300	- 3.1%
Pacific Coast	14	16	23	17	16	15	3	1	-17.7%
Lower 48 Onshore Regions									
East	2,106	1,523	1,286	1,065	915	914	916	909	-11.9%
Southeast	441	391	409	415	276	263	297	343	- 5.6%
S. Louisiana and S. Texas	1,982	1,365	1,376	1,685	1,359	1,147	1,921	1,909	+ 0.9%
Southwest	3,511	3,580	3,184	3,319	2,595	2,416	2,688	2,579	- 5.4%
West	1,889	1,776	2,191	2,874	2,281	1,857	2,197	1,956	+ 0.6%
Alaska	38	34.	18	12	60	5	10	11	-15.0%
U.S. Total	10,313	9,059	8,879	9,701	7,693	6,922	8,357	8,008	- 3.7%

Source: 1966 to 1971 data are taken from the "U. S. Drilling Summary Reports," published annually in the American Association of Petroleum Geologists Bulletin.

1972 data are from the Oil and Gas Journal, Jan. 29, 1973, p. 103.

1973 data are from the Oil and Gas Journal, Jan. 28, 1974, p. 114.

TABLE 24

FOOTAGE OF EXPLORATORY WELLS DRILLED BY REGION, 1966 - 1972
(000)

REGION	1966	1967	1968	1969	1970	1971	1972	Compound Rate of Change
Lower 48 Offshore Regions								
Gulf of Mexico	3,907	4,011	4,405	3,400	2,039	3,219	2,446	- 8.4%
Pacific Coast	124	126	265	142	147	156	33	- 7.9%
Lower 48 Onshore Regions								
East	3,876	3,004	2,898	2,648	2,316	2,295	2,697	- 6.3%
Southeast	3,439	3,101	3,177	3,440	2,404	2,360	3,675	- 1.8%
S. Louisiana and S. Texas	15,585	12,683	11,979	13,744	11,110	9,539	10,067	- 6.7%
Southwest	17,955	16,242	15,573	17,584	13,517	12,477	13,701	- 5.0%
West	9,940	9,612	12,489	16,415	13,087	10,295	12,307	+ 2.8%
Alaska	397	345	172	93	633	47	118	-12.7%
U. S. Total	55,223	49,124	50,958	57,466	45,253	40,388	45,044	- 3.8%

Source: "U. S. Drilling Summary Reports" published annually in the American Association of Petroleum Geologists Bulletin.

Table 25 shows exploratory footage in states of the three regions which account for most onshore exploration and production -- the West, the Southwest and South Louisiana and South Texas. Together these regions had 80.0 percent of all U. S. exploratory drilling footage in 1972. As noted above, the West was the only major producing region to increase the number of wells and exploratory footage in the past seven years.

Within the Western region, Colorado experienced a large increase in exploratory drilling footage from 1966 to 1972 -- from 1.3 to 3.0 million feet. Montana and Wyoming also showed large gains during this period. All major producing states in the other regions had substantially less exploratory drilling footage in 1972 than in 1966 except Oklahoma, where the 1972 level almost equals the 1966 level.

Drilling expenditure data are available only for total exploratory and development drilling. As shown in Table 26, total drilling expenditures in 1966 exceeded drilling expenditures in 1972, using constant dollars. However, 1972 expenditures were more than double 1966 expenditures in the Southeast. In 1966, the only state with substantial drilling in this area was Mississippi. By 1972, expenditures in Alabama and Florida had risen sharply. Expenditures declined substantially in the Southwest, South Louisiana and South Texas, Alaska, and the Pacific Coast. Elsewhere, 1972 expenditures were not substantially greater than 1966 expenditures.

We estimated exploratory drilling expenditures by determining the weighted average costs per foot of all types of drilling for each region and using this figure to calculate costs for exploratory drilling only. This assumes equal costs per foot for both exploratory and development drilling, while exploratory wells probably cost less. This bias is, however, consistent for all regions. Table 27 presents the results of our analysis.

Total U. S. exploratory drilling expenditures declined more than total drilling expenditures from 1966 to 1972. Exploratory drilling expenditures in 1972 were only 87.4 percent of the 1966 levels, whereas total drilling expenditures in 1972 were 92.9 percent of 1966 levels. Exploratory drilling expenditures in the West and Southeast were much higher in 1972 than 1966. Exploratory expenditures in all other regions declined.

Data reviewed thus suggest that the West and the Southeast are experiencing substantial increases in their share of exploratory activity, largely offset by reductions of exploratory activity in the Southwest and South Louisiana and South Texas. However, the Southwest still has the largest volume of exploratory activities -- measured in number of wells and footage, and South Louisiana and South Texas retain the largest share of expenditures. Exploratory activity has declined in the Pacific Coast, the Gulf of Mexico and Alaska since 1966. Exploration in offshore

TABLE 25

FOOTAGE OF EXPLORATORY WELLS
IN MAJOR PRODUCING STATES OR SUBDIVISIONS OF STATES
IN THE WEST, SOUTHWEST AND SOUTH LOUISIANA AND SOUTH TEXAS,

1966 to 1972

(000)

Major Producing States	1966	1967	1968	1969	1970	1971	1972	Compound Rate of Change
WEST:								
California	1,811	1,916	1,849	1,594	1,437	1,085	1,108	- 9.1%
Colorado	1,337	1,442	1,405	2,839	2,782	3,146	3,000	+20.9%
Montana	1,160	1,269	2,233	2,578	1,895	1,163	1,482	+ .9%
New Mexico	1,279	1,025	971	1,274	892	649	1,128	+ 4.3%
Wyoming	2,517	2,585	4,042	4,844	3,949	2,246	3,259	+ 1.6%
SOUTHWEST:								
Kansas	3,354	4,703	4,128	3,905	3,078	2,748	2,927	+ 2.6%
North Louisiana	1,571	1,182	1,352	1,148	794	1,031	983	- 7.7%
North Texas	9,262	7,596	7,149	8,541	6,302	5,641	6,289	- 6.4%
Oklahoma	3,090	2,337	2,439	3,243	2,777	2,441	2,908	+ 0.0%
SOUTH LOUISIANA AND SOUTH TEXAS								
South Louisiana	6,661	5,165	5,417	5,447	4,566	4,316	4,434	- 6.1%
South Texas	8,924	6,518	6,562	8,297	6,544	5,223	5,700	- 7.0%

Source: "U.S. Drilling Summary Reports" published annually in the American Association of Petroleum Geologists Bulletin.

TABLE 26

PERCENTAGE DISTRIBUTION OF TOTAL DRILLING EXPENDITURES IN CONSTANT DOLLARS BY REGION, 1966 & 1972

(000000)

REGION	1966		1972	
	Amount	Percent	Amount	Percent
Lower 48 Offshore Regions				
Gulf of Mexico	$ 406.3	19.6%	$ 421.2	21.9%
Pacific Coast	$ 27.0	1.3%	$ 8.5	.4%
Lower 48 Onshore Regions				
East	$ 113.7	5.5%	$ 115.5	6.0%
Southeast	$ 52.2	2.5%	$ 115.3	6.0%
S. Louisiana and S. Texas	496.8	24.0%	$ 412.6	21.4%
Southwest	$ 632.6	30.5%	$ 505.6	26.1%
West	$ 302.2	14.5%	$ 317.6	16.5%
Alaska	$ 40.9	2.0%	$ 32.7	1.6%
TOTAL	$2,071.7	100.0%	$1,925.1	100.0%

Source: Joint Association Survey of the U.S. Oil and Gas Producing Industry, 1966 and 1972.

The GNP deflator was used to derive constant dollars; 1958 = 100.

TABLE 27

PERCENTAGE DISTRIBUTION OF ESTIMATED EXPLORATORY DRILLING EXPENDITURES IN CONSTANT DOLLARS BY REGION, 1966 and 1972

(000000)

REGION	1966		1972	
	Amount	Percent	Amount	Percent
Lower 48 Offshore Regions				
Gulf of Mexico	$ 142.9	19.5%	$ 105.9	16.5%
Pacific Coast	$ 5.2	.7%	$ 1.2	.2%
Lower 48 Onshore Regions				
East	$ 30.3	4.1%	$ 23.4	3.5%
Southeast	$ 28.2	3.8%	64.1	10.0%
S. Louisiana and S. Texas	$ 222.3	30.3%	$ 150.6	23.5%
Southwest	$ 174.7	23.7%	$ 136.6	21.3%
West	$ 92.9	12.6%	$ 145.1	22.6%
Alaska	$ 38.6	5.3%	$ 15.2	2.4%
TOTAL	$ 734.6	100.0%	$ 641.9	100.0%

Source: Joint Association Survey of the U.S. Oil and Gas Producing Industry, 1966 and 1972.

The GNP deflator was used to derive constant dollars; 1958 = 100.

California and Alaska has been curtailed by environmental considerations in the past five years. In Alaska, technological constraints also are a factor. Leasing policies impact strongly on the share of exploration in the Gulf.

Table 28 allows a longer term view of the growing role of offshore regions in oil and gas production. It shows total wells, footage, and expenditures for all offshore and onshore areas, 1960 to 1973. The offshore figures predominantly represent drilling activity in the Gulf. The most striking illustration of the increasing importance of offshore regions is the fact that from 1960 to 1972, the number of wells, footage drilled, and expenditures in constant dollars doubled offshore whereas all declined sharply onshore.

Table 29 illustrates graphically the growth in the offshore regions' share of exploratory activity. In 1960, offshore drilling represented only 1.2 percent of total wells and 3.0 percent of total footage. By 1967, offshore drilling represented 9.0 percent of total footage -- the highest percent attained to date. The offshore regions' share of drilling expenditures -- which have averaged about one-fourth of total drilling expenditures since 1966 -- is the best indicator of their attractiveness, because it measures the resources operators devote to offshore operations. These have shown the highest compound rate of change, +6.8 percent during this 12-year period, compared to +4.6 percent for the number of wells and +4.1 percent of footage drilled.

A review of geophysical crew months worked during this period, as a measure of the volume of geophysical activity, shows a similar trend. Crew months have approximately doubled offshore and have been sharply reduced onshore. For all measures of activity except geophysical crew months, 1968 was the peak year offshore. As mentioned earlier, a very large Federal lease sale was held in 1967 which resulted in the subsequent surge of exploratory activity. (During the four preceding years, total Federal acreage leased in the Gulf represented less than one-third of the acreage leased in the 1967 sale.) As expected, geophysical activity offshore reached its peak in 1966, prior to the large increase in exploration.*

Comparing the absolute number of offshore to onshore crew months would understate the actual share of geophysical activity offshore because a much larger area can be surveyed offshore within a month than onshore. Geophysical activity offshore also is different than onshore, because the chances of very large discoveries still exist offshore. Thus, the survey process offshore is more of a random search for stratigraphic traps than onshore, where the area surveyed generally is smaller and expectations for prospective discoveries are more conservative.

Regional Analysis of Proved Reserve Additions

The only offshore region for which data on annual proved reserve additions are available is the Gulf of Mexico and these have been published only since 1970.

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* Department of Interior, Bureau of Mines Information Circular 8575.

TABLE 28

COMPARISON OF THE VOLUME OF EXPLORATORY AND DEVELOPMENTAL DRILLING BETWEEN ALL ONSHORE AND OFFSHORE REGIONS, 1960 - 1973 (First Three Quarters)

	Number of Wells Drilled			Footage Drilled (000)			Drilling Expenditures* (000000)		
	Offshore	Onshore	Offshore as % of Total	Offshore	Onshore	Offshore as % of Total	Offshore	Onshore	Offshore as % of Total
1960	538	43,595	1.2%	5,608	180,772	3.0%	$ 200.9	$2,146.3	8.6%
1961	606	43,382	1.4%	6,084	180,558	3.3%	$ 221.0	$2,071.3	9.6%
1962	760	43,184	1.7%	7,755	185,802	4.0%	$ 256.1	$2,179.1	10.5%
1963	786	41,067	1.9%	8,170	173,310	4.5%	$ 271.7	$1,877.1	12.6%
1964	995	42,491	2.3%	10,179	178,569	5.4%	$ 328.7	$1,901.3	14.7%
1965	1,037	38,559	2.6%	10,889	167,916	6.1%	$ 385.9	$1,780.3	17.8%
1966	1,127	33,394	3.3%	11,870	146,053	7.5%	$ 466.2	$1,605.5	22.5%
1967	1,365	30,173	4.3%	12,918	131,088	9.0%	$ 522.3	$1,432.9	26.8%
1968	1,322	28,254	4.5%	12,619	130,510	8.8%	$ 545.9	$1,424.2	27.7%
1969	1,191	28,290	4.0%	11,650	137,055	7.8%	$ 519.6	$1,516.8	25.5%
1970	1,058	26,119	3.9%	10,238	126,652	7.5%	$ 442.6	$1,464.2	23.2%
1971	884	24,156	3.5%	9,007	115,637	7.2%	$ 369.0	$1,305.6	22.0%
1972	993	25,450	3.8%	10,000	125,535	7.4%	$ 433.5	$1,491.6	22.5%
1973 First Three-quarters	770	18,827	3.9%	7,181	91,920	7.2%	N/A	N/A	N/A
1960 - 1972 Compound Rate of Change	+ 4.6%	- 5.5%		+ 4.1%	- 4.0%		+ 6.8%	- 4.1%	

Source: Joint Association Survey of the U.S. Oil and Gas Producing Industry, 1960 through 1972.

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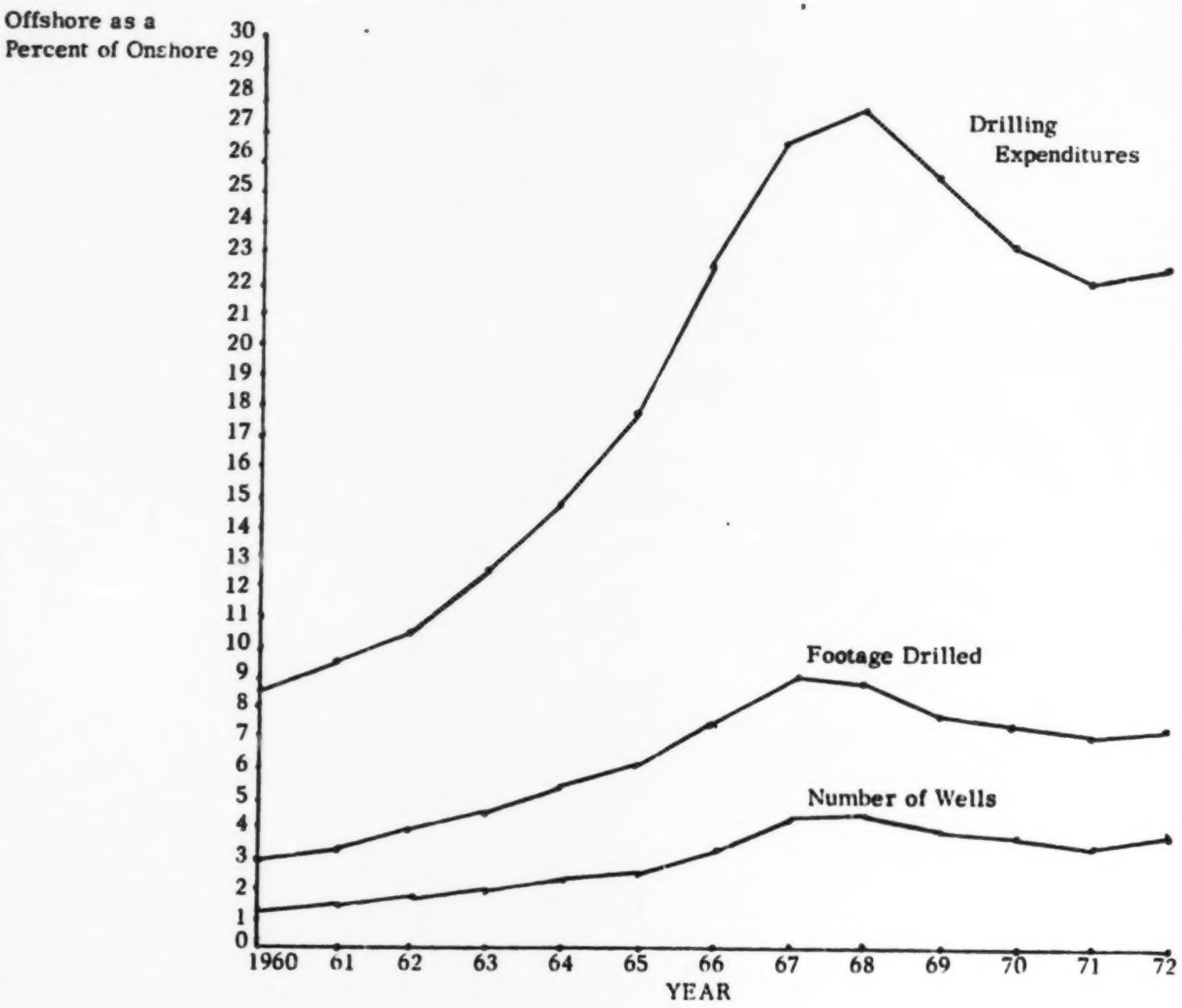
*In constant dollars, using the GNP deflator; 1958 = 100.

TABLE 29

ILLUSTRATION OF OFFSHORE REGIONS' SHARE OF EXPLORATORY ACTIVITY



We therefore must limit our discussion to the three-year period of 1970 through 1972.

Presumably, the volume or intensity of drilling activity is reflected in the proved reserve additions for each region. However, proved reserve additions are an imperfect measure of the volume or success of exploratory activity because first year estimates of proved reserves are often based on very limited knowledge and may represent only a small fraction of total proved reserves which ultimately will be credited to the reservoir.

There are four categories of proved reserve additions. Two are derived from new field and new pool discoveries based on wildcat drilling, another from enlargements of a proved area based on information gained from extension drilling, and the fourth category of reserve additions (or subtractions) is based on the geological and engineering knowledge gained from development drilling and production history. Proved reserve additions based on extension or development drilling and production history have no direct relationship to exploration in the current period.

An estimate of the original oil-in-place in new fields discovered each year also is published. This represents the estimate of total oil in the reservoir regardless of whether or not it can be "produced under current operating and economic conditions" (the criteria which must be met by hydrocarbons classified as proved reserves). The estimate of original oil-in-place best reflects the success of new field wildcat drilling in the current period.

Table 30 shows the regional distribution of proved oil reserve additions based on new field and new pool discoveries only and Table 31 shows the distribution for total proved oil reserve additions. Also shown in Table 30 are 1972 estimates of original oil-in-place in fields discovered in 1972. Only proved reserve additions are available for natural gas. These are shown in Table 32.

Table 30 shows that the Gulf of Mexico has contributed a substantial proportion of proved reserve additions based on exploratory drilling during each of the three years shown. In 1970 and 1972, the Gulf's share of new field and new pool proved reserve additions equalled 40.8 and 36.8 percent of the total -- the largest share of any region. By comparison, the Gulf represented only 21.9 percent of total drilling expenditures and 5.4 percent of exploratory drilling footage in 1972. The high success rate in the Gulf amplifies our earlier conclusion that the Gulf is gaining in exploratory activity relative to onshore regions.

In 1971, the largest share of proved reserve additions was found in the Southwest. The two lower 48 onshore regions which were the major contributors of reserve additions during the three-year period were the Southwest and South Louisiana and South Texas. These regions were not characterized by success rates as high as

TABLE 30

PROVED RESERVE ADDITIONS BASED ON NEW FIELD AND NEW POOL DISCOVERIES, 1970 - 1972 AND 1972 ESTIMATES OF OIL IN PLACE IN 1972 FIELD DISCOVERIES

REGION	Percentage Distribution of Proved Oil Reserve Additions			1972 Estimates of Oil-in-Place In 1972 New Field Discoveries
	1970	1971	1972	
Reserve Additions (000)	367,674*	155,710	278,430	502,058
Gulf of Mexico	40.8%	14.7%	36.8%	9.3%
East	4.3%	8.6%	2.5%	7.9%
Southeast	5.7%	4.1%	7.6%	26.4%
S. Louisiana and S. Texas	18.7%	27.3%	19.5%	17.0%
Southwest	13.1%	36.1%	21.6%	3.0%
West	17.4%	9.3%	10.8%	36.5%
Alaska	--	0.0%	0.0%	0.0%

*Excludes the Alaskan new field discovery for which 9,604,000,000 barrels of reserves were added to proved reserve additions in 1970. This represented over 95% of total new field and new pool discoveries in 1970.

TABLE 31

PERCENTAGE DISTRIBUTION OF TOTAL PROVED OIL RESERVE ADDITIONS BY REGION, 1970 - 1972

REGION	1970	1971	1972
Reserve Additions (000)	2,889,325*	2,317,732	1,557,848
Gulf of Mexico	18.3%	9.4%	14.4%
East	1.9%	2.5%	.8%
Southeast	2.2%	8.2%	3.6%
S. Louisiana & S. Texas	12.3%	14.4%	11.0%
Southwest	51.9%	54.0%	34.3%
West	13.1%	9.7%	32.9%
Alaska	--	2.0%	3.4%

*Excludes Alaska. The huges discovery of 9,799,513 barrels in Alaska credited to reserves in 1970 represented 77.2% of total proved reserve additions that year.

TABLE 32

PERCENTAGE DISTRIBUTION OF TOTAL PROVED NATURAL GAS RESERVE ADDITIONS BY REGION, 1970 - 1972

REGION	1970	1971	1972
Reserve Additions (mcf)	11,524,761*	10,135,772	9,791,126
Gulf of Mexico	56.4%	23.7%	22.8%
East	7.2%	5.7%	8.2%
Southeast	1.6%	---**	1.9%
S. Louisiana and S. Texas	---**	19.3%	16.7%
Southwest	25.5%	33.0%	38.1%
West	9.3%	14.5%	9.9%
Alaska	---	3.8%	2.4%

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*Excludes Alaska. The huge discovery of 26,073,808 mcf in Alaska credited to reserves in 1970 represented 69.3 percent of total proved reserve additions that year.

**Reserve additions were negative because reductions in estimates exceeded additions to reserves.

the Gulf. While 21.6 percent of reserve additions were in the Southwest in 1972, this region had 26.1 percent of total drilling expenditures and 30.3 percent of exploratory drilling footage. Similarly, South Louisiana and South Texas accounted for 19.5 percent of 1972 proved reserve additions; but they accounted for 21.4 percent of drilling expenditures and 22.5 percent of exploratory drilling footage.

The last column shows 1972 estimates of oil-in-place for 1972 field discoveries. Total estimated oil-in-place is almost double the reserve additions credited to new field and new pool discoveries in 1972, so its magnitude is substantial. The West was credited with over one-third of incremental estimated oil-in-place in new fields, and the Southeast with about one-fourth. The Gulf's share is relatively modest at 9.3 percent.

Total proved oil reserve additions are shown in Table 31. The Gulf's share in each year is greatly reduced compared to new field and new pool discoveries only, because much of the Gulf's reserve additions were based on exploratory drilling rather than development and production history. The lower 48 region with the largest share of proved reserve additions is the Southwest, followed closely by the West. The West, however, experienced the greatest increase in the share of proved reserve additions from 1970 to 1972.

Table 32 shows that the Gulf of Mexico was the source of over half of total natural gas reserve additions in 1970. Subsequently, the Gulf's share declined to about one-fourth. The other major source of proved gas reserves was the Southwest.

As the Table footnotes show, both 1970 oil and natural gas reserve additions from the lower 48 states were dwarfed by the proved reserve additions credited in 1970 to the 1968 Alaskan new field discovery. It accounted for 77 percent of proved oil reserve additions and 69 percent of proved natural gas reserve additions in 1970.

Our analysis has focused on comparing levels of exploratory activity and growth rates among regions. Generally, we concluded that the region making the most substantial gains, as suggested by various analyses, is the West. To summarize our findings, the West:

- Has the greatest increase in the share of exploratory wells and drilling footage from 1966 to 1973.

- Is the only region to show an increase in the absolute number of exploratory wells and footage during this period. For the U. S. as a whole, exploratory wells drilled declined at a compound rate of -3.7 percent whereas the West showed an increase of 0.6 percent. Exploratory footage declined at a compound rate of 3.8 percent whereas the West showed a gain of 2.8 percent.

- Has a modest gain in the share of total and exploratory drilling expenditures in constant dollars from 1966 to 1972.

- Has the largest share of estimated oil in place in 1972 field discoveries, and a very large increase in the share of total proved oil reserve additions from 1970 to 1972.

The areas where the West does not stand out as dominant are the volume of proved reserve additions based on exploratory drilling for oil and all proved reserve additions for natural gas. For example, in 1972 the West had 27.2 percent of all exploration and 9.9 percent of all natural gas reserve additions. This comparison raises the issue of the impact of expectations for successful drilling on exploration. For instance, if proved reserve additions are one-half as great per foot drilled in one region than another, does drilling equal footage in both regions at equal costs per foot represent twice the "effort" in the region where the probability of success is only half as great? An affirmative response requires the conclusion that drilling in the West represents a more intense "effort" than drilling footage statistics alone suggest, since the payoff in terms of proved reserve additions is not proportionate to drilling activity. Conversely, because the probability of successful drilling is higher in the Gulf than other regions, the magnitude of drilling effort should be discounted here. The conclusions to be drawn are not obvious. The more intense effort in the West probably rests on the assumption that reserves of a substantial volume exist and can be produced, or that reserves can be produced faster, and/or at lower cost. Many factors may impact on the decision of where to concentrate exploratory effort -- for instance, expectations of better natural drive, lower lease costs, less production restrictions through market demand prorationing, etc. -- and each may influence cost and production expectations differently. The relatively lower apparent effort in the Gulf results because fewer dry holes are needed to discover and delineate the reservoirs. But if economic reserves are believed to exist, a lower drilling success rate alone, as suggested by experience in the West, does not appear to discourage future exploration.

These issues are peripheral to the scope of our analysis. We have attempted to identify the regions gaining in the share of exploratory activity. The measures we use -- number of wells, footage, and expenditures -- generally suggest the same conclusions. We assume that exploratory drilling decisions are made on the basis of expectation of discovering economic reserves and have selected measures to reflect the decisions. Our analysis does not enable us to identify definitive reasons for the concentration of exploratory effort in any region.

Several other qualifications of our analysis must be noted. First, while we generally have focused on the trade-off of exploration among regions, in the real world each region represents a portfolio of prospects which compete on the margin. Identifying attractive prospects at this level would require substantial additional effort and time. Thus, while we identified regions and, in some instances, states which are gaining on the margin, identifying the trade-off between favorable prospects within regions was beyond the scope of this study. A second consideration in evaluating our conclusions is that production of hydrocarbons in the next 15 years, as in the previous 15 years, will predominantly reflect development of areas with currently well defined oil-in-place. Current exploration will impact on the distribution of marginal production between regions in a shorter time period, but not on the bulk of production.

In conclusion, total exploratory activity based on any measure has declined onshore in the past decade. The decline has not been uniformly distributed across all regions. The West, particularly Colorado, Montana, and Wyoming, has experienced substnatial increases. While still representing a small share of total exploratory activity, the Southeast also has made substantial gains.

Activity in the Gulf has been particularly volatile, due in part to the timing of Federal lease sales. The Gulf gained relative to competing onshore regions on only one measure -- the share of exploratory wells drilled in 1973 compared to 1972. However, in comparing all offshore regions -- predominantly representing the Gulf -- to all lower 48 onshore regions, the offshore regions have gained substantially. This results because exploration in the Gulf has increased relative to onshore areas other than the West and Southeast and because exploration in the Gulf was not significant prior to the late 1950s. Recent economic conditions and Federal policies suggest that offshore exploration will probably exceed former peaks reached in 1968 in a relatively short time.

Effects of Leasing Policies and Other Supply Controls on the Distribution of Exploration Among Regions

On a combined basis basis, offshore regions have greatly expanded their share of exploratory and developmental drilling at the expense of onshore regions in the past two decades. Our analysis shows that three regions, the Gulf of Mexico, the West and the Southeast have increased their share of drilling -- measured by the number of wells, footage, or expenditures -- while the share of drilling in other regions generally has declined. This section reviews the impact of leasing policies and other supply controls on the trade-off among competing regions.

Leasing Policies

Leasing policies have impacted on the trade-off in drilling activity among regions. Public land generally can be leased for oil and gas exploration at the initiative of the operator. Public land leasing is governed by the Mineral Leasing Act of 1920 which permits the leasing of public lands, with certain exceptions such as national parks, for mineral exploration. The great majority of oil and gas leases issued by the United States have been noncompetitive leases, issued pursuant to Section 17(c) of the Act which provides that "the person first making application for the lease who is qualified to hold a lease under this Act shall be entitled to a lease of such lands without competitive bidding." The acreage under any lease is limited to 2,560 acreas but there is no limit to the number of leases any individual can hold. A nominal filing and rental fee are charged. The royalty payment under noncompetitive leases is 12-1/2 percent in amount or value of the production removed.

Section 17 of the Act provides that lands "within known geological structures of a producing oil or gas field shall be leased to the highest responsible qualified bidder by competitive bidding." A lease cannot exceed 640 acres and a graduated royalty payment is required. The royalty rate varies from 12.5 percent on oil wells producing 50 barrels or less per day to 25.0 percent on wells producing 400 barrels or more per day. Royalty on natural gas is 12.5 percent on wells producing 5 million cubic feet or less and 16.67 for wells producing more.

While the lease request for noncompetitive leases originates with the party who seeks the lease, the offer to grant a competitive lease is initiated by the Interior Department. Typically, a person who desires to obtain such a lease makes the initial contact anyhow, by requesting that the land be offered for leasing. Frequently, offers are a result of the determination that drainage is occurring with respect to land adjacent to leased acreage. Finally, it sometimes occurs that land within a producing structure is discovered to not be covered by a lease. The Department has the right to reject all bids on any basis. Generally, all bids may be rejected because the Government concludes that they are inadequate and a later sale could generate higher bids.

In 1972, 88,326 acres of Federal onshore land was leased competitively at an average bonus payment per acre of $63. Production from all competitive onshore leases in 1972 totalled 34.7 million barrels of oil and 107.7 mcf of gas.* Table 33 shows how pro-competitively leased public lands, and all other public lands.

TABLE 33

OIL AND GAS PRODUCTION IN
FEDERALLY ADMINISTERED PROPERTIES, 1972

	Oil		Gas	
	Barrels (000,000)	Percent	MCF (000,000)	Percent
Competitively Leased Public Lands	34.7	6%	107.7	3%
All Other Public Lands	182.4	30	1,016.7	24
Outer Continental Shelf	378.5	64	3,038.6	73
Total	595.6	100%	4,163.0	100%

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* Includes all public onshore lands leased prior to and during 1972.

Most onshore public land production is from noncompetitive leases. Over two-thirds of oil and natural gas production on Federally administered lands is on the Outer Continental Shelf.

Thus, onshore -- at least with regard to public lands -- operators are relatively free to explore whenever they choose. Offshore leasing is governed by long-term leasing policies which are influenced by environmental considerations and national energy policy. The selection of offshore areas available for leasing, at least in the past five years, has been curtailed due to environmental considerations. This is especially true for offshore California, where a moratorium on leasing in state waters and a halt of OCS leasing was in effect from 1969 to 1974. Thus, leasing policies have influenced the distribution of offshore exploration between offshore regions, tending to favor the Gulf relative to other offshore regions.

It is not evident, however, that offshore operations would have accelerated more rapidly overall in the absence of leasing constraints. Exploration offshore is very expensive and the industry has devoted an increasingly large share of exploration expenditures to offshore exploration -- about one-fourth of the total in the past several years. Yet, as of 1971, only 18.4 percent of all OCS acreage leased had been classified as productive. Another 9.1 percent was classified productive, shut-in. The remainder has been returned to the Federal government or is being held for future exploration.

Industry exploration experience offshore has been good and the potential for finding substantial economic reserves is believed to be better than for any onshore area except Alaska. Because the proposed schedule of leasing tracts in the outer continental shelf has been greatly accelerated and additional leases may be offered on the Atlantic OCS, the share of exploration offshore can be expected to increase. About one million acres were leased on the OCS in 1973, bringing the total OCS acreage leased since 1953 to about 5.6 million acres or 3.0 percent of the Outer Continental Shelf off the U. S. mainland.

The Interior Department had issued a revised leasing schedule in 1973, which would have tripled annual acreage leased beginning in 1974, to three million acres per year. However, in his January 23rd energy message this year, the President announced plans to increase OCS lease sales to 10 million acres per year, beginning in 1975. As a result of opposition by environmentalists and coastal states, the Interior Department probably will scale down the amount of acreage leased to a target of leasing 10 million acres in 1975.

In implementing the expanded leasing program, the Department of Interior is revising the procedure of selecting sites for leasing. Until now, sites chosen for leasing were selected by the Interior Department from tracts nominated by the oil and gas industry. Following the President's January 24, 1974 energy message, which initiated the accelerated lease schedule, the Interior Department instituted a "two-tiered" system for lease nominations. The Department has identified 17 areas in the Atlantic, Pacific, Alaska and Gulf of Mexico regions, and has asked industry, states and environmentalists to rank them in order of preference. Other areas also can be nominated. The Interior Department will use these rankings, along with its own evaluations, to select regions for OCS development. Industry will then nominate specific tracts from these regions, as it does now. The Interior Department has not released estimates of expected production from OCS acreage under the modified 10 million acre program. However, under the President's original January 23rd proposal, the Department estimated that OCS acreage would furnish sufficient production to allow the U. S. to be self-sufficient for its energy needs by 1986 -- at consumption levels of 10 billion barrels of oil and 28 million cubic feet of natural gas. (In 1973, total U. S. consumption was 6 billion barrels of oil and 23 trillion cubic feet of natural gas; offshore production was 1 billion barrels of oil and 6 billion cubic feet of natural gas.)

This projection assumes that capital and drilling equipment will be available to permit only normal delays between lease sale and production:

- Gulf of Mexico -- 2 years within 200 meters and 3 years beyond 200 meters.
- California OCS -- 4 years for initial 2 sales and 3 years thereafter.
- Atlantic OCS -- 8 years.
- Alaska OCS -- 10 years.

The rapid acceleration of OCS lease sales -- even at the annual rate of 3 million acres -- can be expected to make strong requirements on the industry's total capital available for exploration. Two results may occur: (1) expenditures for exploration onshore may be further reduced -- absolutely and as a share of total expoloration expenditures, and (2) bonus payments may reverse their trend of setting record levels at each sale.

Our discussion of offshore acreage has focused on the Outer Continental Shelf, where virtually all offshore operations are located. Potentially, operations also could extend to the Outer Continental Slope -- the submerged lands lying in 200 to 2,500 meter water depth. An acceleration of OCS lease sales will result in a more rapid leasing of acreage in the Outer Continental Slope. Future lease sales in the Gulf are expected to focus on deep water sales, although to date only one sale has included deep water acreage, and much of the Atlantic, California, and Alaskan offshore acreage to be leased lies in the Outer Continental Slope. The March 28, 1974 lease sale of acreage in offshore Louisiana included tracts in water depths to 1000 feet, while the deepest producing well in the Gulf is in water depths of only 345 feet.

The Outer Continental Slope totals 330 million acres. Table 34 below, shows the distribution of Continental Shelf and Slope acreage by offshore regions. Almost two-thirds of the shelf and slope are offshore Alaska. Ice problems will limit operations to a small fraction of this acreage for at least a decade. Fundamental research on ice topography, ice movement, subsea soils (including permafrost), and ice strength are required.

TABLE 34

DISTRIBUTION OF OUTER CONTINENTAL SHELF AND SLOPE ACREAGE AMONG OFFSHORE REGIONS
(in millions)

	Outer Continental Shelf	Outer Continental Slope	Total Shelf and Slope
Gulf of Mexico	44	42	86
Atlantic Coast	79	29	108
Pacific Coast	15	38	53
Florida Coast	49	46	95
Alaska	373	175	548
Total	560	330	890

Source: Ocean Industry, September 1973, p. 131.

Supply Controls

Various government policies and economic conditions interact to create incentives or disincentives for exploration -- overall and its distribution among regions. The major factors influencing the trade-off between competing onshore and offshore regions are discussed briefly in the remainder of this section.

1. Economic Conditions: Crude prices declined from 1960 to 1972. Table shows average per barrel wellhead prices in constant dollars from 1960 to 1972.

Declining prices tended to reduce the incentives for domestic exploration across the board. Offshore prospects remained attractive because production costs for a flush field were anticipated to be low relative to much onshore production. Bonus prices paid for offshore leases showed that producers anticipated profitable operations. Offshore costs, inclusive of bonus payments and exploration costs, are high but operating costs tend to be lower than onshore.

TABLE 35

AVERAGE WELLHEAD PRICE OF U.S. CRUDE OIL
1960 - 1974

Year	Per Barrel Wellhead Price
1960	$2.79
1961	2.76
1962	2.74
1963	2.70
1964	2.65
1965	2.58
1966	2.53
1967	2.47
1968	2.40
1969	2.41
1970	2.35
1971	2.39
1972	2.32
1973 (preliminary estimate)	2.53
1974 (estimated 1st quarter)	4.00

Source: Independent Petroleum Association.
The GNP deflator was used to derive constant dollars;
1958 = 100.

Market factors currently are making many prospects -- particularly onshore -- economic which were not pursued at lower prices. In 1973, the price of domestic oil from established wells rose from an average of $3.50 to $5.25 a barrel. Oil from newly discovered wells and increased production from old wells was removed from controls last August, and oil from marginal stripper wells was decontrolled last December. In January, the price of decontrolled oil rose to $10.00 per barrel. During the first quarter of 1974, the average price of domestic oil was $6.65 -- double last year's level of $3.89 in current dollars.*

Industry estimates are that the number of domestic wells drilled may increase up to twenty-five percent in 1974 over 1973, dramatically reversing a steady decline over the past fifteen years. Thus, in response to higher prices, the volume of exploratory and development drilling can be expected to increase in all regions in 1974; the onshore region which probably will experience the greatest increase in drilling based upon our analysis of past drilling trends in the West. Within this region, the states which have experienced the most rapid growth and which probably will continue to do so are Colorado, Wyoming, and Montana. From 31 to 58 percent of the total land area of these states was leased for oil and gas operations in 1973. The average for the total onshore U. S. was 16 percent, and only about three percent of the outer continental shelf has been leased for oil and gas operations.

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* Oil and Gas Journal, May 27, 1974, p. 26.

While price levels will act to increase the volume of exploration, a constraint which may reduce the rate of growth in the short term is a shortage of drilling equipment both on and offshore and for drilling platforms offshore. The availability of equipment has not been a factor in determining the volume of exploration in the past, but shortages due to sudden increases in demand are anticipated for 1974 and 1975. The waiting period for equipment already approaches one-and-a-half years for some manufacturers.

2. Technology: Technological capabilities may provide a constraint, in the near term, on expansion of operations in the Outer Continental Slope, if deep water acreage becomes available under accelerated lease schedules. Virtually all of the Outer Continental Slope is beyond current technological capability but near term developments anticipated in deep water technology would permit operations in the Slope off the Gulf, Atlantic, and Pacific Coasts.

Production to date has been in OCS waters which are 400 feet deep or less. The industry has the capability currently to produce in water depths up to 600 ft. Exploratory drilling has been conducted in water depths to 1,500 feet and the technology is available to drill in up to 2,000 feet of water. Drilling in very deep water is from drill ships, whereas fixed platforms are suitable for waters in depths of 400 feet or less. In the Gulf, approximately 2,800 fixed structures are now standing. Deep water production techniques are being developed and tested; two sub-sea production systems capable of operating in 800 foot depths are being tested in the Gulf. For deeper water, further development in flow line installation, floating, storage and the vertical riser to bring the oil to the surface is needed.

Pipeline technology also must be furthered to allow deep water production. Pipelines currently can be developed for water depths up to 600 feet. Efforts are underway to develop 30-inch pipelines in water depths up to 3,000 feet.

The developments described are all capable of operating in moderate climates. Equipment which can withstand hurricanes, very high waves, or arctic climates will require further work and a longer time period to be operational.

If deep water acreage is made available in the near future by lease sales, we anticipate that industry will finance necessary technological developments at higher levels than currently to allow deep water operations to proceed with minimal delay. The consequence may be a further reduction of expenditures for onshore exploration.

3. Regulation by the Federal Power Commission: The relationship between natural gas prices and supply has been a major subject of continuing concern in proceedings before the FPC and several staff studies have addressed this question. It currently is being considered before the Senate Commerce Committee in hearings on numerous bills to change the regulation of the natural gas industry.

The difficulty in resolving this issue arises because of the joint product nature of natural gas. All oil reservoirs contain some gas, but not always in sufficient amounts to permit economic production. Or, in wildcat drilling, the objective may be to find oil, but instead the reservoir contains only gas.

Prior to World War II, natural gas was regarded as a by-product of oil production without significant commercial value. Subsequently, its status changed to a co-product, which was produced if found incidentally in the search for oil, as long as price covered the marginal cost of production. As demand for gas increased, and a major pipeline network became established, gas supply came to depend primarily on the price of gas rather than of oil. The sharp increase in gas supplies during the 1950s, as gas prices increased with the development of markets and the decline in supply additions during the 1960s when gas prices were restrained through regulatory action, suggests that new supply of natural gas is responsive to price. Over the period 1950 to 1970, on the average, a ten percent increase in gas prices precipitated an exploratory gas drilling increase of 14 percent.

The amount of gas produced from oil wells -- associated gas -- has declined from 55 percent of the total in 1950 to 21 percent in 1972. This is the result of two factors: (1) producers now allocate a percentage of exploratory resources directly to natural gas exploration, and (2) prorationing requirements restrict production from oil wells and thereby reduce associated gas production. There are no state production allowables for gas, so nonassociated gas may be produced at any desired rate.

A certain amount of gas would be forthcoming even if it were only sold below allocated cost. Due to the sunk cost nature of much of the cost of producing gas, marginal cost usually is very low. Large amounts of associated gas were flared before the advent of high pressure, long distance pipe lines. As long as the price of oil suggested that reserves were economic, exploration would take place. Thus, the supply of associated gas is sensitive to the price of oil as well.

The issue of the effect of FPC regulation on the distribution of exploration is more difficult. To the extent that natural gas was produced if found incidentally in the exploration of oil, FPC price regulations had no significant effect. For the growing share of nonassociated gas, maintaining prices below the market value will restrict the share of natural gas exploration in high cost areas -- particularly offshore, Alaska, and for very deep onshore reserves. The determination of costs remain at issue, and thus of the price needed to provide an adequate rate of return on capital. For associated gas, sunk costs and dry hole costs must be allocated to the oil and gas produced.

Currently, a two-tier price system is in effect for old and new gas.* The administration supports complete decontrol of wellhead prices, and industry spokesmen support this proposal because it will provide funds necessary for future exploration to meet growing demand. This conclusion is disputed by critics who feel that increased revenues may not lead to proportionate increases in exploration and production. Several bills to extend the Federal Power Commission's jurisdiction also are being considered. A bill introduced by Senator Stevenson (D. Ill.) would deregulate gas only from small producers while regulating inter- and intrastate sales of the largest 25 producers and also would establish a Federal corporation to conduct natural gas exploration.

4. Conservation Regulations: In Section III, we concluded that state conservation regulations generally tend to promote relatively high cost opportunities. Production allowables generally increase more than proportionate to well depth increases. Additionally, offshore allowables are higher than onshore allowables for wells of equal depths, to reflect greater costs of offshore operation. These factors combine to make offshore, high cost opportunities, attractive to onshore opportunities.

In order to examine further the question of the impact of state conservation regulations on the decision to explore on or offshore, we reviewed the conservation regulations of Louisiana, the state with the most extensive offshore operations.

Louisiana, as well as most large producing states, has market demand prorationing. Under prorationing, a state regulatory agency determines the total crude oil production for a state and allocates the total among the various reservoirs and to wells within each reservoir. Market demand prorationing requires that allowable production be established on the basis of estimated demand. The law extends the ordinary meaning of the term waste to include "the producing of oil or gas from a pool in excess of transportation or marketing facilities or reasonable market demand." (Louisiana R.S. 30:1).

The regulatory commission meets monthly to estimate market demand. The U. S. Bureau of Mines also provides each state with an estimate of demand. Allowable production is set on a monthly basis.

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* Gas produced from wells discovered prior to April, 1973 must be sold at controlled prices, whereas the price of gas from wells discovered after this date is not controlled.

The allowable then must be distributed among pools. (The actual procedure is not one of determining in sequence first the pool allowables and second the well allowables. The usual practice is to apply the formula that governs the production of wells in a pool and thus determine the total allowable for the pool.) According to the depth of the pool, each well therein is assigned a top or schedule allowable that represents a hypothetical 100 percent rate of production if it were not restricted. The amount increases with pool depth. The permitted rate of production then can be expressed as a percent of the schedule allowable.

A schedule of allowables adopted in March, 1953 applies to fields discovered since that time in Louisiana. Separate schedules apply to pools on and offshore. Table shows the allowables for wells spaced 40 and 80 acres. Allowables vary not only with depth, but with the number of acres per well. Allowables increase as acreage increases to encourage wider well spacing. Onshore, allowables increase 50 percent for drilling on 80 rather than 40 acres for all depths. Offshore, allowables increase more as well depth increases. The range in the allowable increase for 80 acres per well instead of 40 is 21 percent for wells 2,000 feet or less in depth to 36 percent for wells 20,000 to 21,000 feet deep. Thus, the incentives for wider well capacity are lower offshore than onshore. However, the costs of drilling offshore act to limit the number of drilling platforms and wells used for each pool and constrain well spacing more than onshore drilling costs.

Allowables do not increase at a constant percentage as well depth increases. Generally, allowables increase a greater percentage for wells on 80 acres rather than 40 acres on and offshore. Offshore allowables increase at lower percentages than onshore allowables for each 1,000 acre increase in well depth. For example, a 40-acre onshore well from 8,000 to 9,000 feet deep has an allowable 11.7 percent greater than a 40-acre onshore well 7,000 to 8,000 feet deep. Offshore, the allowable for a 40-acre well under the same circumstances increases only 9.8 percent. However, the offshore allowable for the 8,000 to 9,000 foot well is 416 bbls/day compared to 239 bbls/day onshore.

Offshore allowables for 40-acre wells are about twice as high as onshore allowables to well depths of 5,000 feet. Then the greater percent increase of onshore allowables reduces the difference steadily, until at 20,000 feet offshore allowables are only about 50 percent greater than onshore allowables. These differences in allowables reflect the fact that offshore production at any depth is more expensive relative to onshore production because of the nature of fixed equipment required. But as well depths increase, onshore costs also soar and reduce the cost differential between operating on and offshore.

An order issued by the Louisiana Department of Conservation in 1960 (Statewide Order No. 29H) requires a different application of the allowables to pools discovered after 1960. The purpose was to encourage wider well spacing. The Order requires that wells be spaced at a minimum of 40 acres, unless an exception is granted by the commissioner. The maximum acreage per well which can be used to compute the allowable on and offshore is 90 acres, so there is no incentive to increase well spacing beyond 90 acres.

TABLE 36

LOUISIANA DEPTH-BRACKET ALLOWABLES

Depth-Bracket (ft.)	Onshore 40 acres	Onshore 80 acres	Offshore 40 acres	Offshore 80 acres
0 - 2,000	80	120	193	233
2,000 - 3,000	95	143	214	262
3,000 - 4,000	114	171	238	295
4,000 - 5,000	134	201	265	332
5,000 - 6,000	159	239	296	376
6,000 - 7,000	186	279	331	424
7,000 - 8,000	214	321	379	486
8,000 - 9,000	239	359	416	536
9,000 - 10,000	274	411	463	600
10,000 - 11,000	310	465	512	667
11,000 - 12,000	347	521	559	733
12,000 - 13,000	383	575	605	797
13,000 - 14,000	431	647	668	884
14,000 - 15,000	483	725	734	976
15,000 - 16,000	557	836	830	1,109
16,000 - 17,000	645	968	942	1,265
17,000 - 18,000	726	1,089	1,053	1,416
18,000 - 19,000	816	1,224	1,167	1,575
19,000 - 20,000	927	1,391	1,307	1,771
20,000 - 21,000	1,057	1,586	1,469	1,998

Source: Louisiana Conservation Department.

Louisiana regulations specifically exempt stripper fields and pools less than 3,000 feet deep from any restrictions created by the acreage factor in the depth-factor schedule. These exemptions do bias against offshore operations because stripper wells and, generally, shallow wells are located onshore. Louisiana makes no special provision for discovery allowables, reflecting the fact that it has not felt the need to provide greater incentives for exploration. Partly, this is because the per-well allowables are high relative to other major producing states.

From our brief review, we conclude that Louisiana's depth-acreage schedule allowables have impacted positively on offshore production. Allowables offshore are higher than onshore at all well depths, and there is less incentive for wider well spacing. Allowables do not increase as rapidly with depth increases offshore, but these differences are not great relative to the large absolute differences in allowables on and offshore.

Offshore production would provide a greater proportion of domestic output in the absence of market demand prorationing restrictions. This also would be true of flush onshore fields. But, given the current structure of conservation regulations, offshore areas have been relatively attractive compared to onshore areas.

Production history in the Gulf of Mexico supports our observation. Table 37 shows annual production in the Gulf of Mexico and Louisiana from 1960 to 1972. (Data on production from offshore Louisiana only are not available. However, over 90 percent of Gulf production is estimated to be from offshore Louisiana, so the share of offshore production for Louisiana shown is probably not much greater than the actual share.)

TABLE 37

OIL PRODUCTION IN THE GULF OF MEXICO AS A PERCENT OF TOTAL LOUISIANA PRODUCTION
(in millions of barrels)

Year	Gulf of Mexico	Louisiana, Total	Gulf as a Percent of Louisiana, Total
1960	81.6	346.3	23.6%
1961	95.2	364.8	26.1
1962	117.2	415.1	28.2
1963	135.2	448.5	30.1
1964	155.3	478.8	32.4
1965	183.7	520.1	35.3
1966	225.8	585.5	38.6
1967	269.3	670.2	40.2
1968	306.2	710.7	43.1
1969	337.9	727.6	46.4
1970	379.5	785.9	48.3
1971	430.4	833.9	51.6
1972	407.1	779.9	52.2

Source: Reserves of Crude Oil, Natural Gas Liquids and Natural Gas, 1972, AGA, API, CPA.

5. Federal Tax Policies: While federal tax laws do not distinguish between onshore and offshore production, *per se*, they distinguish between various types of costs whose relative importance differs on and offshore. The expensing of intangible drilling costs provision tends to increase the attractivenss of relatively high cost, including offshore, opportunities. If less costs could be expensed immediately, higher cost opportunities would not be developed as rapidly.

The percentage depletion allowance tends to have the opposite effect. Its provisions favor low risk prospects which afford early production capacity, because a percentage of the sales value of oil may be deducted from taxable income. However, the effect of percentage depletion cannot be considered independently of prorationing restrictions. Because percentage depletion is based on sales (or profits), operators would favor production where allowables are highest -- offshore -- and, generally, deeper pools both on and offshore.

The tax provision which gives U. S. firms a 100 percent tax credit for foreign royalties encourages foreign exploration and development.

6. Import Policy: U. S. import controls have restricted domestic exploration and production. The Mandatory Oil Import Control Program was effective from 1959 to early 1973 but, in effect, imports have not entered the U. S. freely since World War II. Supply controls in the form of production allowables enforced by state regulatory commissions were designed to compensate deeper wells and stripper wells for their higher costs. Thus, high cost production was encouraged at the expense of lower cost opportunities. Excess capacity also was fostered because the practice of granting allowables to wells led to the drilling of more wells per reservoir to expand production without increasing capacity. Given these output controls, the price of oil was not free to move. Hence, there was no market mechanism to cut back high cost output. Increased imports would not have reduced price, but merely would have curtailed domestic production on a barrel-for-barrel basis. Low cost output would have been cut back most, because stripper wells have no production limits, whereas less expensive prorated wells would have made up the deficit.

Foreign oil looked more and more attractive as domestic oil prices rose. From 1948 to 1956, voluntary import restrictions were reasonably successful in limiting the volume of imports. Cooperative industry behavior toward this end was encouraged by the government, but even under these favorable circumstances, the cooperation was limited and insecure because not every company would benefit. The established importers -- seven majors with large Persian Gulf operations -- were keenly interested in expanding imports.

Exploration incentives domestically were reduced because cheap foreign imports were much more profitable at the inflated U. S. prices. Further, the proration system commits a large proportion of output to old, high-cost, wells, so the rate of production from rich new deposits is severely curtailed. Given only modest expectations from domestic exploratory effort, investment in development or foreign exploration becomes more attractive.

The price of domestic oil was increased substantially during the Suez crisis in 1956. When Persian Gulf exports were resumed in 1957, the pressure of increased imports became so strong that mandatory import quotas were instituted to protect domestic production. Import controls also were justified by the argument that they were needed to stimulate domestic exploration. But the number of exploratory wells drilled in the U. S. continued to decline because of the excess capacity caused by previous exploration, development, and cutbacks in allowables, thereby extending the time required to recover an investment in exploration. Quota exemptions for some refined products were allowed. One result was the construction of refineries in the Caribbean by U. S. majors, because residual fuel oil could be imported into PAD I without restriction.

Domestic crude prices declined slightly from 1957 through 1972, partly due to Federal Trade Commission actions, the 1967 oil embargo, a relaxation of production restrictions, and, most recently, the Economic Stabilization Program. Drilling for new fields and new pools declined steadily during this period. The highest level of postwar exploration occurred in 1956, when 11,395 exploratory wells were drilled.

The effect of import controls, coupled with production restrictions and the depletion allowance, on the distribution of exploration between on and offshore opportunities probably has, on balance, favored offshore production relative to onshore production of low cost opportunities but not of onshore higher cost opportunities. Excess capacity fostered by production restrictions and import policy curtialed domestic exploration generally. Exploration which did occur was encouraged in areas where allowables would be high enough to permit profitable operations, given anticipated operating costs and prices. Since offshore allowables are higher than onshore allowables for any given well depth, this encouraged offshore operations. Onshore higher cost operations -- stripper well production, secondary recovery operations which often have different allowables, and deeper wells -- also were encouraged. Other things being equal, the percentage depletion allowance makes already producing properties most attractive and wildcat properties least attractive, because its value is based on out-put. Thus, it tends to encourage the development of known fields rather than wildcat exploration where commercial pay-offs are in the more distant future. But, the value of the depletion allowance depends on output production, so exploration may be encouraged offshore or for deep reserves onshore where allowables are highest.

V

ENVIRONMENTAL HAZARDS AND SAFEGUARDS

Environmental damage may result from the operating procedures utilized or accidents. The nature and magnitude of environmental damage resulting from either accidents or routine operating procedures depends upon the stage of the operation and the characteristics of the site.

Environmental Risks Associated with Offshore Geophysical Exploration, Drilling and Production, and Pipelines

There is no evidence of any significant environmental risk at the stage of geophysical exploration in offshore areas.[*] The three basic types of surveys that are conducted include seismic, magnetic and gravity surveys, with seismic reflection surveys accounting for over 90 percent of all offshore geophysical exploration. These surveys do not involve drilling, explosions, samplings or disturbance of the seabed unless dynamite shooting is used to generate sound waves for seismic surveys. This method is infrequently used, having been replaced by use of air guns, vibroeis, or sleeve exploders.

The drilling and production of hydrocarbons pose a risk to the environment, primarily due to the likelihood of accidental oil spills due to natural disasters, equipment failure, or human error. OCS operating regulations and clean-up measures maintained by the industry and Coast Guard reduce but do not eliminate the risks.

From 1953 through 1972 -- when nearly all the wells were drilled in the U.S. OCS, 43 major accidents occurred. Table 38 shows these accidents by type of damage and cause. Nineteen were associated with drilling, 15 with production, and 4 with pipelines. Over the 19 years, there has been an average rate of 0.5 percent drilling and production accidents per successful OCS well drilled. During the same period, 8 blowouts were recorded in state waters.

The frequency of OCS accidents generally increased as activity increased until 1968, when the accident frequency peaked. It has been decreasing since then. The 1969 Santa Barbara blowout -- in releasing from 18,500 to 780,000 barrels of oil -- raised serious questions on the adequacy of OCS technology. Since Santa Barbara, three major production platform accidents have occurred in the Gulf of Mexico. In the Shell accident (1970), estimates of oil lost range from 53,000 to 130,000 barrels. The Chevron accident (1970) resulted in loss of 30,500 barrels. Finally, the Amoco accident (1971) resulted in loss of 400 to 500 barrels.[*]

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[*] CEQ, *OCS Oil and Gas: An Environmental Assessment*, 1974.

The diminishing number of drilling accidents since 1968 reflects improvements in both technology and practice. The frequency of production accidents has not decreased so markedly, perhaps because old offshore production facilities and pipelines do not, in all instances, meet the specifications now called for in new facilities and pipelines.

For an oil field find of medium size,* there is about a 70 percent chance that at least one platform spill over 1,000 barrels will occur during the life of the field. For a small oil field find, there is about a 25 percent chance of one platform spill over 1,000 barrels and for a large oil field find, there is over a 95 percent change of a platform spill over 1,000 barrels, during the life of the fields. The probability of pipeline spills follows the general pattern exhibited by platform spill statistics. There is about a 40 percent chance that 250 million barrels of oil will be handled between large spills. If a large platform spill does occur, there is an 80 percent chance that the volume will exceed 2,380 barrels and a 35 percent change that it will exceed 23,800 barrels.

Both short and long-term damage to the environment can result from a major spill. Short-term effects in an estuarine or shallow water zone may have severe and visible destructive effects on plants and wildlife. Short-term effects in deep waters may not be readily apparent but may have a severe impact because marine animals and plants in deeper regions generally are not as diverse as those found in shallower areas. Short-term effects also include damage to the beaches and coastal areas. Long-term effects of a major spill or a series of minor spills also may be severe and not apparent. These include the destruction of food sources, loss of larvae, and mutation of marine plant and animal species.

Chronic routine discharge of oil, primarily in waste water, also presents a hazard. The oil content of waste water discharged in OCS operations is limited to an average of not more than 50 ppm under OCS Order No. 8. In the offshore Louisiana OCS, 214 of 1935 structures discharge about 180,000 barrels of waste water per day. The oil content of this waste water is estimated to equal about 7 bbl's per day. While this amount does not produce an immediate adverse effect upon the environment, in conjunction with other discharges, the effect may be significant. Discharges of sewage and other harmful liquid waste materials are prohibited by Geological Survey requirements. All solid waste except drilling muds, drill cuttings, and sand must be incinerated or transported to shore.

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* CEQ Report, op. cit., based on an M.I.T. Report entitled, "Analysis of Oil Spill Statistics," 1974. A medium find was defined by M.I.T. as 2 billion barrels of oil in place and a gas/oil ratio of 1,000:1. A small find was defined as 500 million barrels of oil and 500 billion cubic feet of gas and a large find as 10 billion barrels of oil.

TABLE 38

MAJOR ACCIDENTS ON THE U.S. OUTER CONTINENTAL SHELF, 1953 - 1972

Accident Results	Cause of Accident					
	Drilling Equipment Failure	Production Equipment Failure	Pipeline Failure	Collision	Weather	Total Accidents
1. Number of Accidents	19	15	4	2	3	43
2. Type of Wells:						
● Oil	0	3	4	1	3	11
● Oil and gas	2	7	0	0	0	9
● Gas	17	2	0	0	0	19
● Other	0	3	0	1	0	4
3. Oil Spillage						
● Number spills	2	10	4	1	3	20
● Oil volume (thousand barrels)	18.5-780	84.-135.4	175	2.6	9.2-9.7	290-1,100
4. Other damage:						
● Deaths	23	33	0	0	0	56
● Injuries	7-8	91-100	0	0	0	98-108
● Fires	7	12	0	1	0	20
● Major rig/platform damage	4	9	0	2	0	15
● Duration	2 hrs. -5.5 mos.	10 min. -4.5 mos.	1-13 days	1 day	1-3 days	10 min. -5.5 mos.

Sources: University of Oklahoma Technology Assessment Group, Energy Under the Oceans: A Technology Assessment of Outer Continental Shelf Oil and Gas Operations (Norman: University of Oklahoma Press, 1973), using U.S. Geological Survey, U.S. Coast Guard, Offshore, and Oil and Gas Journal data.

Offshore drilling and production does not contribute significantly to air pollution. A burning gas well will not have great impact; a large amount of oil from spills, if not recovered, may evaporate into the air.

Offshore structures may detract from the aesthetic, recreational, and archeological value of coastal areas. Depending upon the tracts, offshore drilling may interfere with commercial fisheries.

Underseas pipeline construction disturbs the seabed and marine life, but this adverse impact is of a temporary nature. The major risk also is from accidental oil spills. The probability of damage due to a rupture of the pipeline can be reduced by adequate burial and by use of pressure sensitive devices to shut off transport when a rupture occurs.

Onshore pipelines present the greatest danger in coastal marshes and estuaries. They may contribute to marsh destruction by erosion, acceleration of fresh water drainage, fostering salt water intrusion, loss of habitat by lands taken for installation of pipelines and onshore terminals and gas treatment facilities, and destruction of vegetation. An oil spill probably would have severe short and long-term impact due to the difficulty of removal.

Environmental Risks Associated with Each Offshore Area

The Gulf of Mexico*

The coastal areas of the five states bordering on the Gulf of Mexico are richly endowed with 12.7 million acres of estuaries and coastal marshes. This represents about two-thirds of the total coastal marshes and one-third of the estuarine water area in the U.S. These waters are very productive of fish and wildlife resources.

The Outer Continental Shelf is very wide in the Gulf, reaching widths of about 140 miles off the Texas-Louisiana border. The climate is moderate and precipitation is abundant (55 inches per year). The Gulf is characterized by severe weather in the form of hurricanes, which has resulted in the toppling of offshore drilling platforms and oil spills.

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* Includes offshore Florida, Mississippi and Alabama in this discussion, in addition to offshore Texas and Louisiana.

These and other characteristics result in the ecological classification of the Gulf as a high energy system. That is, the naturally generated energy supply is sufficient to maintain a large and diverse population of plant and animal life. The coastal area is the site of 25 National Wildlife Refuges and refuges also are maintained by each state. The Gulf is one of the major commercial fishing areas in the U.S. In 1971, the value of the commercial fishing catch represented one-third of the value for the total U.S. Shipping is an important commercial activity in many areas of the Gulf. Sport fishing and recreation activities also are extensive in this region.

The environmental impact of exploratory and development activities on newly leased tracts of course depends on the specific characteristics of the tract. Generally, it can be assumed that debris from routine operations and oil spills may have a negative impact on the refuges, estuaries, marshlands, and beaches of the Gulf. Commercial and sports fishing also may be adversely affected. Pipelines and storage facilities would not be permitted in Federal or state refuges or park areas, so their negative impact would be diminished.

Platforms actually appear to have a positive impact on sports fishing because of the artificial reef effect of offshore platforms which provide protection, food sources, spawning sites, and spatial orientation markers for fish. However, they present a substantial danger to ships because of the likelihood of collisions with the platform or with floating debris which may result in the spillage of oil and additional debris or cargo. From 1962 through 1971, the Coast Guard reported 24 incidents of collisions between vessels and fixed platforms.

Unburied pipelines on the seafloor damage trawling nets. A significant amount of shrimp trawling occurs in water depths where pipelines remain unburied.

The marine life of the Gulf probably would be most affected by adverse environmental impacts of increased exploratory and development activity. Accidental loss of debris, discharge of drill cuttings, sand, drilling fluids, the burial of pipelines, and the accidental spillage of oil or other toxic materials could result in short and long-term damage to many species. Most severe damage would probably result from large spills. Few studies have addressed the effects of low level, continuous spillage in offshore water. Small spills of fractions of a barrel are estimated to occur on the order of a thousand times a year in the Gulf. These long-term, low level spills may accumulate and eventually cause significant damage to marine life. For example, the level of poisons derived from crude oil may increase at each level of the food chain.

The Pacific Coast

Although several wells have been drilled in the Oregon and Washington OCS, no significant discoveries have been made and no further exploratory drilling is anticipated in the near term. The California continental shelf is believed to have good petroleum potential in many areas. The petroleum potential of the entire Santa Barbara Channel and the seaward extension of the Los Angeles Basin is considered excellent. A particular hazard of the Santa Barbara Channel is the likelihood of earthquakes.

Two earthquakes of magnitude 6.0 or larger (great earthquakes are magnitude 8.0 or greater) have occurred in the Santa Barbara Channel. Both were large enough to result in surface faulting. While there have been no great earthquakes, scientists have found that for Southern California, the frequency of small earthquakes provides a good estimate of the rate of occurrence of large earthquakes. They calculate that a magnitude 6.0 earthquake should occur once every year in Southern California, and a magnitude 8.0 earthquake should occur once in 52 years. Such a great earthquake anywhere in Southern California probably would have destructive effects on the Santa Barbara Channel.

Intense ground shaking in the Channel during an earthquake could be expected. Very high waves also have been recorded in previous earthquakes. It is not known presently which of the channel faults are seismically active. In the past, onshore oil wells have been damaged by sub-surface faulting, but no surface oil spills have resulted. Storage tanks and pipelines also have been damaged by seismic ground shaking.

Environmental damage resulting from the effects of earthquakes on offshore operations are likely to be:

- Rupture of oil pipelines carrying oil from platforms to shore, resulting in oil leakage. Volumes of oil spilled should be small, because present regulations require cutoff valves in the pipelines to prevent further oil pumping if a leak occurs. Existing pipelines carry about 500 to 700 barrels of oil per mile.

- Partial or complete destruction of a drilling platform. Unless wells are at a critical stage of development, damage should be minor. Completed wells have chokes and automatic cutoff valves at the sea floor.

Over 2,500 wells have been drilled offshore California on state and Federal leases. As mentioned earlier, only two serious accidents have occurred -- the platform A blowout and the pipeline break, both in the Santa Barbara Channel. The most severe impact of the platform blowout was the death of about 4,000 birds. Biologists generally conclude that permanent changes in the channel were minimal.

A moratorium on drilling in state waters was immediately imposed after the platform A blowout. Consideration is now being given to lifting the drilling ban in some state offshore areas, and the Department of Interior has asked the oil industry to nominate tracks for leasing in 1975 in the Southern California OCS. (The state of California, however, has set aside from drilling as sanctuaries 2,574,000 acres in certain tideland areas.) The call for nominations covers an area of 7.7 million acres extending as much as 110 miles from shore. Oil reserve estimates are as high as 70 billion barrels.

The Atlantic Outer Continental Shelf*

The areas of the Atlantic OCS showing the greatest possibility of commercial hydrocarbon reserves include: the Baltimore Canyon Trough, extending from the coasts of New Jersey to North Carolina; the Georges Bank Trough off the coast of New England; and the Southeast Georgia Embayment. Each of these areas lies at least 30 miles and as far as 200 miles from the U.S. coastline. The sub-surface geology and climate of these areas is such that environmental hazards could be greater than either the Gulf of Mexico or offshore California. The CEQ report** states that high environmental risk is involved in the development of the Northern Baltimore Canyon and the Southeast Georgia Embayment. Onshore impacts also are likely to be major. Many offshore areas, particularly the Georges Bank area, are major commercial fishing regions. Drilling in these areas could be expected to be opposed by commercial fishing interests. Many areas also are characterized by extensive commercial shipping. While Federal Regulations (33 CFR Sec. 209.135(b) 1971) do not allow the placement of structures in shipping fair ways, accidental collisions are more likely to occur in areas heavily trafficked by ships.

Offshore Alaska

The only offshore production today is from Cook Inlet. The most serious problems are the result of severe weather and sea conditions. Average annual wave heights are about three times as great as in the Gulf of Mexico, and severe storms and surface winds are expected. Low air and water temperatures necessitate special design features on equipment and fixed structures. Some regions of the OCS are free of ice only during the summer months. A particular species of plankton forms the basis of the food chain for marine fauna in the Alaska OCS. Large spills of oil or other toxic materials may have very severe impacts if they damage this species of plankton. The CEQ report concludes that the environmental risks in the Gulf of Alaska are greater than in any Atlantic OCS region.

Transportation of oil produced on or offshore Alaska -- particularly by tanker -- also represents a critical impact consideration.

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* Includes Florida's Atlantic Coast in this discussion.

** CEQ, OCS Oil and Gas, An Environmental Assessment, April 1974.

Environmental Risks Associated with Onshore Geophysical Exploration, Drilling and Production

The environmental hazards of onshore hydrocarbon operation can be discussed in the context of incremental increases in exploration and production for most regions. The environmental impacts are less potentially severe than those of offshore operations, where very large increases in operations in currently productive areas or operations in never before explored areas are under consideration.

Onshore geophysical exploration is conducted by a variety of surface and aircraft methods. Some geophysical surveys include use of explosives and require cutting of trails through promising areas. The environment is disturbed temporarily in these circumstances. Additionally, explosions sometimes damage water wells and irrigation facilities in close proximity to the test areas.

Wildcat wells are drilled to verify the existence of hydrocarbon deposits. A heavy duty temporary road to support the drilling rig and other equipment must be built and a well site must be cleared and graded. In forest areas, this may involve the cutting of trees. Disposal of drilling "mud" also may have adverse impact on the area. The wildcat well requires water, which may be obtained by drilling a water well or laying pipelines to a distant source of water. If oil or gas is discovered, additional testing equipment is brought to the area. If the well is dry, the hole must be plugged and state regulations generally require that the site be resotred.

Development drilling occurs within the boundaries of a known producing pool to find additional productive zones. Impact will be marginal in already producing areas.

Secondary recovery operations also will generally have little incremental adverse impact. Abandonment may result in some of the gathering systems, flow lines, and buried pipe being left in place, if regulations do not require their removal.

The principal risk of onshore operations is the danger of harmful substances such as oil, chemicals, brine, and waste materials entering the surface or ground water systems. Spills or leaks may result from: corrosion of pipelines or container vessels; pipeline breaks from vibrations, earthquakes, etc.; burning pits; open ditches; and blowouts. Both road building and canal dredging also may adversely affect water quality.

Large amounts of salt water usually are produced as oil fields age; this results in substantial disposal problems. The IOCC estimates that 25 million barrels of salt water are produced daily. Sub-surface disposal is regulated by state water resource agencies and disposal of salt water is not permitted in fresh water streams. However, significant salt water pollution can occur, resulting in long-term soil sterilization, with consequent effects on plant and animal life and water quality.

Water pollution also results from barges transporting petroleum inland and on coastal waterways. Pollution may be due to loading and unloading operations, collisions, bilge disposal, and human error. The Coast Guard estimates there were 295 barge spills in 1970, with an average spill size of 66 barrels.

Significant adverse impacts on air quality are unlikely to result from onshore drilling and production. The impact on air quality stems principally from the emission of particulates into the atmosphere due to vapor venting from storage tanks or the burning of petroleum and other chemical products; some disturbance also results from noise and vibrations. Feeding and nesting habits of birds and animals may be disrupted for the duration of operations.

Blowouts may damage land quality but they are infrequent. Blowout preventers are standard equipment but may misfunction. 106 blowouts occurred in drilling 273,000 onshore wells from 1960-1970.

Secondary recovery operations based on water injection impact on the environment primarily by their demand on the water supply. The American Petroleum Institute defines primary recovery as oil or gas recovered by any method (natural flow or artificial lift) that may be used to produce them through a single well bore. The fluid enters the well bore by action of the reservoir's native energy. Secondary recovery involves more than one well bore and the reservoir's native energy is augmented by the injection of fluids with or without heat. The decision as to whether or not to use recovery techniques is based largely on economic conditions. Secondary recovery is more expensive than primary recovery but, at current prices, secondary recovery operations are becoming more and more attractive relative to exploration. The decision as to whether to use water, gas, or a miscible is based upon reservoir characteristics, economic factors, and local conservation laws. If large volumes of gas are produced with no sales outlet or where the wellhead price of gas is low, the injection of gas may be the most economical method to yield a higher recovery.

Typical water injection rates for wells are from 5 to 10 B/D/ft. for pattern flooding. Three B/D/ft. is considered minimum and a higher rate of 10-20 B/D/ft. can be anticipated for aquifier injection. Reservoir response can be expected when two-thirds of the voidage created by primary production is filled by water. On the average, 8.62 barrels of water are required to produce one barrel of oil.[*] Estimates are that 1.1 to 1.3 barrels of this water is obtained from local surface or ground water sources; the remainder is the brine produced along with oil. If water injection is widely increased, the demand for water in addition to brines may increase substantially. The potential impact is greatest in arid regions.

Anticipated production expenses of secondary recovery in the U.S. are about $1.00/bbl and capital investment required is about $.20/bbl.

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[*] Water Use in Petroleum and Natural Gas Industries, Bureau of Mines Circular 8284, 1966.

Environmental Risks Associated with Each Onshore Area

With the exception of Alaska, the environmental risks associated with onshore exploration and production do not vary greatly among regions. Generally, the incremental environmental damage can be expected to be lowest -- in terms of land area disrupted, water and air pollution, disturbance of wildlife, and conflict with recreational and commercial activities -- in areas where oil and gas operations already are extensive.

Environmental considerations are far more complex in Alaska as a result of the severe climate and fragile nature of the Arctic flora and fauna. Examples of unique aspects include:

- Thawing of permafrost from oil pipeline heat loss and construction activities. The materials then could become unstable and flow or slide, especially on slopes.
- Disruption of wildlife in a wilderness environment.
- Disruption of normal surface drainage and stream flows.
- Effects on the environment andwildlife of transportation of oil by pipelines.

Evaluating the Environmental Tradeoffs Between Regions

Our brief review of the potential adverse environmental impacts of exploration in competing offshore and onshore areas suggests that potential environmental damage differs substantially between onshore and offshore regions. The greatest hazard of offshore exploration is the possibility of significant short or long-term damage to marine plant and animal life due to chronic or massive oil spills. Coastal marshes and estuaries appear to have the most susceptible ecological systems to damage from oil or other hazardous materials. The recreational, commercial, and aesthetic values of coastal areas also may be threatened.

Onshore, the greatest potential hazard is land and surface and sub-surface water pollution from oil spills or discharge of salt water and other harmful materials. A longer term hazard is the potential adverse impact on the water supply by large increases in secondary recovery operations based on water injection. Both onshore and offshore, chronic or massive oil spills may increase levels of harmful substances in organisms at various levels of the food chain.

The incremental environmental damage to be anticipated from exploration of any site depends greatly on the extent of existing operations. This is the result of two factors: (1) there is a short-term but unavoidable one-time impact associated with many operations, such as laying pipelines or the constructing of storage facilities, and (2) familiarity with operations in a particular region can be expected to reduce the rate of future accidents.

We conclude that potential environmental hazards will primarily depend on the location of exploratory activity and anticipated subsequent development rather than its volume or rate. The extent of ongoing operations and the ecology of exploratory drilling sites are the primary factors which determine potential environmental hazard.

Our review of drilling activity showed that offshore areas -- primarily reflecting operations in offshore Louisiana -- gained substantially compared to all onshore regions. We thus conclude that a continued rise in the share of exploratory activity in the entire Gulf Coast area can be expected. This appears to be a reasonable assumption because about 5.5 million acres in the Louisiana OCS remain untapped. Four million acres currently are under active lease and another 4.5 million were turned back after drilling or rejected in previous sales. In addition, there are 10.5 million untested acres in the Texas OCS.

Exploratory activity in the Texas and Louisiana OCS probably would have less potential adverse impact on the environment than in other offshore areas. Currently, about 1,900 platforms and 6,000 miles of pipeline are found in the Louisiana OCS alone. These facilities might serve additional exploratory operations.

Some areas of offshore California also are characterized by oil and gas operations but the volume does not approach that of offshore Texas and Louisiana. Most of offshore Alaska, Florida, Alabama, and Mississippi and all of the Atlantic OCS have never been explored. Exploratory activity in these regions can be expected to result in greater adverse environmental impact because all facilities and equipment must be introduced for the first time. In some areas, the ecology may be more vulnerable to harm from oil or hazardous material spillage than in currently productive OCS areas. Another consideration is the equipment requirements of particular OCS areas, such as offshore Alaska or very deep OCS waters, where newly developed equipment will be used which has not been tested by operating experience.

Once exploratory drilling is initiated in a previously unexplored area, the necessary facilities and equipment required to support the operation have predictable (and generally minor) environmental impacts and these impacts probably will not vary greatly at higher volumes of exploratory drilling or rates of growth.

The volume of future exploration and its rate of growth, of course, also are factors in determining potential environmental impact. But we conclude that the location of exploratory drilling is the primary determinant of potential hazards. For example, increasing either the volume or the rate of growth of exploratory drilling while continuing to distribute drilling activity among regions on the current basis probably will have less adverse impact than redistributing the current volume of drilling among regions by increasing drilling in previously unexplored areas. However, if the total volume of exploratory drilling does increase substantially, and continues to grow at an increasing rate, we cannot expect its distribution among regions to follow the current pattern. Most of the increases in exploratory drilling will be offshore or in Alaska because the possibility of finding large reserves is highest in these regions and this is where producers are spending a growing share of their exploratory dollars. Our analysis showed that exploratory expenditures offshore grew rapidly in contrast to a decline in the growth of expenditures in onshore regions over the past 12 years.

The potential environmental hazards of exploration and production can be compared across regions by assessing their share of high risk characteristics. Examples of major high risk characteristics as suggested by our analysis include:

- The extent of existing operations,
- Offshore operations generally,
- Sensitive ecology
- Severe climate or extreme variations in weather,
- Limited use of equipment based on existing technology,
- Existence of food industry (farming, fishing) or commercial shipping in areas to be drilled, and
- Large use of area's water supply.

We have developed a chart illustrating how an analysis might be developed by comparing the frequency of these high risk characteristics. As an example, the chart compares the frequency of high risk characteristics for onshore Alaska, the Gulf of Mexico's Outer Continental Shelf, the Gulf of Mexico's Outer Continental Slope, and Colorado. The analysis shows that both onshore Alaska and the Gulf's Outer Continental Slope present greater potential hazards than the Gulf's Outer Continental Shelf. Colorado has only one high risk characteristic -- extensive use of area water supply, and this assumes widespread future use of secondary recovery techniques for wells developed from future exploration as well as current primary recovery operations.

CHART 1

COMPARISON OF THE FREQUENCY OF HIGH RISK CHARACTERISTICS AMONG FOUR REGIONS

High Risk Characteristics	Alaska Onshore	Gulf of Mexico Outer Continental Shelf	Gulf of Mexico Outer Continental Slope	Colorado
Limited or No Existing Operations	X		X	
Offshore		X	X	
Sensitive Ecology	X			
Severe Climate or Possibility of Severe Weather Conditions	X	X (hurricanes)	X	
Equipment Based on New Technology Required	X		X	
Area Also Characterized by Food Producing Industries or Extensive Commercial Shipping		X		
Extensive Use of Area Water Supply				X
Total Number of High Risk Characteristics	4	3	4	1

A useful assessment of potential environmental hazards would require detailed analyses. The acutal potential drilling sites must be compared and the list of high risk characteristics can be much more detailed. Additionally, the characteristics could be weighted according to their relative importance, so that potential drilling sites could be ranked from highest to lowest potential hazard. (We did not weight the characteristics in our example, but the extent of existing operations and very severe weather conditions should be weighted most heavily.) A sufficiently detailed analysis would illustrate areas where operating regulations and other required safeguards should be reviewed and modified as appropriate to minimize potential risks.

Further analysis is required to determine how much money is available, at various oil prices, to pay for newly imposed environmental controls. For newly leased offshore areas, operators can be expected to reduce their bonus bids according to their expectation of the cost of the new environmental controls. That is, the total amount of the bonus that would have been paid in the absence of new controls at any anticipated price level is available to finance new controls. If new controls cost more to implement than the bonus which would have been paid, no bids would be offered. At current prices, however, high enough bonuses can be expected to continue, which should be sufficient to cover any new environmental controls.

For existing operating areas, some amount of the recent price increases also should be available. An estimate of finding and operating costs in 1967 for oil was made by McKelvey for offshore Louisiana and the lower 48 states. Table 39 shows these estimates, adjusted upwards for inflation through 1973, and shows estimates of amounts available for environmental controls at three price levels -- $5.00, $7.50, and $10.00 per barrel.

Table 39

NET REVENUES PER BARREL AT THREE PRICE LEVELS FOR LOWER 48 ONSHORE AND OFFSHORE OIL PRODUCTION

	$5.00		$7.50		$10.00	
Costs Per Barrel	Gulf of Mexico	Lower 48 Onshore	Gulf of Mexico	Lower 48 Onshore	Gulf of Mexico	Lower 48 Onshore
Finding Costs: (Lease acquisition, geophysical and geological exploration, successful drilling costs, dry hole costs, lease facilities)	$1.68	$1.24	$1.68	$1.24	$1.68	$1.24
Operating Costs: (Production, transportation, overhead)	.78	1.04	.78	1.04	.78	1.04
Royalties:	.85	.63	1.20	.95	1.70	1.25
Total	$3.31	$2.91	$3.66	$3.23	$4.16	$3.53
Net Revenues (Includes income taxes and return)	$1.69	$2.09	$3.84	$4.27	$5.84	$6.47

The table shows constant finding and operating costs per barrel as prices rise. This is inaccurate in the long run, as higher prices will encourage the development of higher cost reserves. Nevertheless, it shows that even at prices of $5.00 per barrel, about $1.50 to $2.00 per barrel net revenue is available after expensed and amortized finding costs, operating costs, and royalties are deducted. (Net revenue includes profit and taxes.) An amount equal to operating costs of $.78 offshore and $1.04 onshore probably could be expended for environmental safeguards at $5.00 per barrel. At higher prices, net revenues increase greatly, so cost would not represent a constraint for implementing most environmental safeguards. Even if average costs increase substantially at higher price levels, net revenues probably would not fall below their level of $5.00 per barrel.

Federal Pollution Control

Our discussion focuses primarily on offshore operations because exploration offshore can be expected to continue to grow at the expense of onshore exploration, and because the potential for severe environmental damage appears to be greater offshore. Numerous Federal and state agencies currently have jurisdiction over offshore oil and gas operations. The agencies which regulate offshore exploration and production in the interests of reducing environmental damage include:

- The Department of Interior -- Office of the Secretary, the Geological Survey, the Bureau of Land Management, and the Bureau of Sports, Fisheries and Wildlife
- The Environmental Protection Agency
- The Coast Guard
- The Army Corps of Engineers
- State conservation agencies
- Adjacent counties or parishes.

The jurisdictions of these agencies frequently overlap, causing confusion to producers and disparities in operational procedures which are potentially hazardous.

The National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA) has led to the preparation of environmental impact statements and opportunities for public review of all leases on the Outer Continental Shelf. The effect of NEPA upon oil and gas leasing on onshore public lands has only recently begun to receive administrative interpretation. At issue is the meaning of the term "major Federal action." Some have concluded that it includes only the original issuance of the lease, not exploratory and development activities subsequently undertaken. Effective April 1, 1972, however, all drilling applications filed for USGS approval pursuant to the Interior Department's Oil and Gas Operating Regulations (30 CFR Part 221.58, 1972) were not approved until after a notice of such application has been publicly posted.

Water Quality

The Department of Interior has jurisdiction over all aspects of offshore operations on the Outer Continental Shelf as they relate to the Department's objectives of: (1) protection of the environment, (2) assuring a fair return to the Federal government, and (3) allowing offshore resources to make a significant contribution to U.S. energy needs as consistent with their safe and orderly removal. This authority is granted by the Outer Continental Shelf Lands Act. Prior to the Santa Barbara oil spill, Interior Department regulations required simply that the lessee shall not pollute the waters of the high seas and authorized a maximum fine of $2,000. Detailed operating regulations were adopted in 1970, and are subject to ongoing modification. The post 1969 regulations purport to be binding on lessees who received their leases before 1969 as well as those after 1969. The legality of imposing additional obligations subsequent to the acceptance by both parties of a binding contract is being challenged by some firms.

The Department currently regulates offshore drilling and production operations at two levels. Operating regulations (30 C. F. R. 250) are issued by the Secretary to be supervised by the USGS regarding exploration, development and production on leased acreage. The Secretary also has authorized the Director of the USGS to issue operating orders for the OCS. Some orders relate to specific acts of particular lessees, but others are applicable to all operations. Their principal emphasis is on the safety of operations and the prevention of oil spills. In 1973, 10 OCS orders were in effect in Southern offshore California and 12 in the Gulf. Several of the orders relate to blowout prevention requirements; others require the installation of subsurface automatic or remotely controlled cutoff devices. Some are housekeeping requirements such as use of drip pans under processing vessels, proper disposal of solid wastes, pressure testing of pipelines, etc. OCS orders set requirements for the structural strength and design of platforms and the seafloor foundation. Platform specifications and all proposed fluid handling systems must be submitted for approval prior to installation. Platforms must have gas detector and fire alarm systems.

As this brief description indicates, OCS operating orders are very detailed in the areas they address. Evidence of compliance is obtained by site and aerial monitoring. During 1972, 2,105 on-site inspections were conducted. Enforcement of regulations in instances of non-compliance may take the form of warnings, shut-in of the operation, or a fine of $2,000 per violation per day.

Detailed data on the number of instances of non-compliance were not maintained until 1970. After the Santa Barbara oil spill of 1969, regulations were more stringently enforced. For example, in 1970 oil companies operating in the Gulf were fined $2.4 million for failure to install subsurface safety devices. No previous fines of this magnitude for one violation had been levied.

In 1956, the Federal Water Pollution Control Act (PL 84-660) was passed which, with its subsequent amendments, is the basic Federal framework for water pollution control today. Administration of the act is the responsibility of the Environmental Protection Agency and the U.S. Coast Guard.

A key provision of the Federal Water Pollution Control Act with regard to offshore oil and gas operations is authorization of development of a plan to provide for coordinated action to minimize damage from spills of oil or other hazardous materials. In response, the Regional or National Oil and Hazardous Substances Pollution Contingency Plan was developed. The plan is effective for all United States navigable waters including inland rivers, lakes, coastal waters and the continental shelf and slope. Its provisions are implemented by all Federal agencies and it promotes coordination with state and local response systems.

Petroleum companies also maintain contingency plans. The 33 producers who account for 98 percent of oil production in the Gulf have established a non-profit organization called Clean Gulf Associates to clean up oil spills. Three non-profit corporations have been formed to clean up oil spills offshore California. Final requirements for implementation of oil spill prevention plans were issued in December, 1973 by EPA. They apply to all non-transportation facilities engaged in producing oil in locations where oil discharges might damage U.S. waters or shorelines.

Federal Regulations (33 C.F.R. Sec. 209.135(b), 1971) require that the Army Corps of Engineers authorize no platform construction permits in or near shipping lanes. Commercial fishing interests also are considered and some leases stipulate that the location of structures may not interfere with commercial fishing.

The Water Quality Improvement Act of 1970 specifically prohibits the discharge of oil in harmful quantities into the navigable waters of the United States, adjoining shorelines, and the contiguous zone. Sources covered by this prohibition include drilling rigs, drilling platforms, storage facilities, and pipelines located within three miles from the shoreline. Offshore facilities located beyond three miles are exempted from this Act because the Secretary of the Interior already had prohibited spills in these waters under the Outer Continental Shelf Lands Act. The Department of Interior issued regulations which define "harmful quantities" under the Act.

Marine water quality also is protected by another recent act, the Marine Protection, Research and Sanctuaries Act of 1972, (usually referred to as the ocean dumping act) which applies to dumping from vessels anywhere at sea of materials transported from the U.S. shore and all dumping in the Territorial Sea and Contiguous zone, regardless of the origin of the waste or the registry of the ship.

Finally, the Refuse Act of 1899, administered by the Army Corps of Engineers primarily to protect navigation, prohibits discharge of refuse in navigable waters from any source. In 1970, a Refuse Act permit program was instituted as a means of accelerating clean-up efforts pending new legislation. The 1972 Water Pollution Control Act Amendments replace this program. They require industries, municipal treatment plants, and other discrete sources to obtain permits specifying allowable amounts and constituents of effluent and a schedule for achieving compliance.

Protection of Fish and Wildlife

Several agencies have authority to promulgate regulations impacting on offshore operations in the interests of offshore fish and wildlife. These include the National Marine Fisheries Service and the Bureau of Sports Fisheries and Wildlife.

Pipeline Regulations

Offshore and Coastal pipeline construction also comes under the jurisdiction of numerous agencies. Federal agencies and their jurisdictions include:

- Bureau of Land Management -- rights of way for common carrier pipelines on the OCS.
- Geological Survey -- producer owned gathering and flow lines on the OCS
- Bureau of Sports Fisheries and Wildlife -- protection of fish and wildlife resources through consultation with the Corps of Engineers in issuing construction permits in navigable waters.
- Army Corps of Engineers
- Federal Power Commission -- grants certificates of convenience and necessity prior to construction of interstate pipelines.
- Interstate Commerce Commission -- grants approval of tariff rates.
- DOT, Office of Pipeline Safety -- establishes standards of pipeline construction, safety and maintenance.

Protection of Coastal Zones

The primary authority for protecting coastal zones -- generally, the area between the three mile seaward boundary of state and Federal waters and an established number of yards inland -- rests with the coastal states. Virtually all coastal and Great Lakes states have enacted or are considering specific laws to protect their wetlands or shorelines. In some states such as California, legislation requires comprehensive coastal zone planning and permits must be obtained from state regional commissions for all development in the coastal zone.

The Coastal Zone Management Act of 1972 (P.L. 92-583) supports regulatory efforts of coastal states by requiring states to create an adequate planning process for locating energy related facilities in the coastal zone such as power plants, deep water ports, pipelines and transmission facilities. It also requires state control over such things as condominium development, industrial development, and citizen access to beaches. Grants to states for planning and management of coastal areas to meet the requirements of the law are provided. The Act is administered by the National Oceanic and Atmospheric Administration, Department of Commerce.

Land Quality

Onshore, the major source of pollution other than routine or accidental oil spills is the disposal of brines (salt water) which are extracted along with oil and gas. (Offshore, water produced generally is compatible with the sea environment and the problem is removal of oil particulates to the required level before disposal.) If not properly disposed, brine may cause severe damage to soil and fresh water streams or reservoirs, resulting in harm to farming operations and wildlife.

States regulate the disposal of brines. Regulations typically require the operator to obtain a permit to dig disposal wells based on applications showing engineering and geological feasibility. The United States Geological Survey provides assistance to the states at the request of state conservation agencies.

A recent study found that about 25 million barrels of salt water are produced daily onshore. Seventy-two percent is being reinjected into the ground, either for secondary recovery of oil or into non-productive salt-water bearing zones that have no commercial value. Injection wells are used to return brines to producing formations. This disposal method prevents surface land pollution and helps to restore the underground equilibrium which existed before the brine was extracted along with the oil and gas. About 12 percent is put into nonpotable water bodies, approved disposal sites, or is suitable for irrigation. Another 12 percent is poured into unlined pits where it perculates in the ground. The remaining 4 percent was reported as having poured into nearby rivers. Disposal into fresh water streams is not allowed in any state.

Air Quality

The Air Quality Act of 1967, (P.L. 90-148) as amended, authorizes the EPA to set emission standards for major pollutants. Oil and gas exploration and production are not major sources of air pollution. Flaring of natural gas is regulated by states onshore and in state waters; Interior Department regulations promulgate standards to reduce air pollution hazards on the Outer Continental Shelf. A new permit system, the National Pollutant Discharge Elimination System, was authorized by the 1972 amendments.

Summary of EPA's Present and Potential Controls

As the previous discussion illustrated, the authority for protecting the environment offshore, along the coast, and inland is shared by many Federal, state and local agencies. The most comprehensive authority for regulating oil and natural gas operations in the Outer Continental Shelf rests with the Interior Department under the Outer Continental Shelf Lands Act. Other Federal laws impact on operations within all navigable waters, and thus apply to state waters, the OCS, and all other waters under the jurisdiction of the United States. Onshore, state conservation agencies have predominant authority over oil and gas exploration and production, regarding both levels of production and environmental safeguards.

EPA's authority to reduce environmental hazards resulting from oil and gas exploration and production primarily stems from the National Environmental Policy Act, which has led to the preparation of environmental impact statements and opportunities for public review of all leases on the Outer Continental Shelf, and the Federal Water Pollution and Control Act, as amended, under which EPA has issued requirements for oil spill prevention and clean-up plans for all operators which, due to their location, might discharge oil in harmful quantities in U.S. waters. Review of possible environmental damage prior to leasing has resulted in the stipulation of mitigating actions by the Interior Department to be undertaken by operators as a condition of obtaining a lease. Under the Federal Water Pollution and Control Act, EPA also issues effluent standards which the states must follow in issuing discharge permits. Sewage discharged from offshore drilling platforms and other facilities also must meet these standards. EPA can initiate enforcement proceedings against dischargers who fail to obtain permits, operators responsible for oil spills who do not make adequate prevention or clean-up efforts, and in other emergency situations.

If leasing on the Outer Continental Shelf and Slope is accelerated as proposed by the Interior Department, EPA has responsibility for insuring that the quality and impact of the review process authorized by NEPA is not diminished due to strong pressures to lease much more acreage in a short time period. Authority to protect the marine environment probably has greatest potential under the Water Quality Improvement Act. The most severe damage offshore would result from a catastrophic equipment failure due to damage by shipping or storms. Accidents offshore are much more harmful than onshore because of the placement of wells on multiple drilling rigs and the logistical problems of repairing the damage and containing a spill. EPA has authority to establish requirements for prevention and clean-up plans for oil spills whereas other agencies -- primarily the Interior Department -- have general authority over day-to-day operating procedures. Thus EPA's enforcement actions are crucial in helping to insure that damage from catastrophic oil spills is minimal.

Onshore, in addition to routine and accidental oil spills, a major potential threat to water quality may be the greatly expanded use of secondary recovery techniques to produce oil. Brines produced along with oil or natural gas generally are used in water injection operations. As mentioned earlier, about 1.25 barrels of "make-up" water are injected to produce one barrel of oil. If the volume of oil produced by water injection increases greatly, water from sources other than by-product brines may be used in great quantities, to the severe detriment of the region's water supply. The impact of wide use of water injection techniques to produce oil on the nation's water supply has not been addressed by research studies. Economic and political conditions only recently combined to provide favorable conditions for such expansion. Under current legislation, state conservation agencies have primary responsibility for managing secondary recovery operations and disposal of brines. (No discharge into offshore or inland waters is involved, because state regulations permit only the return of brine into underground reservoirs, seepage into the ground, or use as a fertilizer when appropriate.) If studies show this to be a problem of national scope, legislation should be supported to place a portion of the responsibility with EPA for monitoring the use of the nation's water supply for this purpose.